NATURAL GAS

Meeting the Challenges of the Nation's Growing Natural Gas Demand

A Report of the
National Petroleum Council

This is a working document
as approved by the
National Petroleum Council.
on December 15, 1999.
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This document is subject to final editing.

DRAFT REPORT

December 15, 1999

This volume is dedicated to the memory of

Collis P. Chandler, Jr.

who passed away during the course of this study.

**Collis was an independent oil and gas producer
who chaired companies
that bore his name for nearly half a century.**

**A former National Petroleum Council Chair,
Collis served on numerous NPC committees and subcommittees,
including the ones that prepared this volume.**

**Collis willingly contributed his experience,
practical insight, and friendship.**

He will be missed.

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DRAFT

December 15, 1999

Dear Mr. Secretary,

On behalf of the members of the National Petroleum Council, I am pleased to submit to you the results of the 1999 study on natural gas, entitled *Meeting the Challenges of the Nation's Growing Natural Gas Demand*. The objective for the study was to provide the requested advice on the potential contribution of natural gas in meeting the nation's future economic, energy, and environmental goals.

The Council is pleased to report that natural gas can make an important contribution to the nation's energy portfolio well into the twenty-first century. Demand for natural gas will continue to increase as economic growth, environmental concerns, and the restructuring of the electricity markets encourage the use of natural gas. More than 14 million new customers will be connected to natural gas supply by 2015 and many more will find their growing electricity needs met by gas-fired generators.

The estimated natural gas resource base is adequate to meet this increasing demand for many decades, and technological advances continue to make more of those resources technically and economically available. However, realizing the full potential for natural gas use in the United States will require focus and action on certain critical factors. These factors include:

- Access to resources and rights of way
- Continued technological advancements
- Financial requirements for developing new supply and infrastructure
- Availability of skilled workers
- Expansion of the U.S. drilling fleet
- Lead times for development
- Changing customer needs.

Each of these factors can be positively influenced, but government, industry, and other stakeholders must act quickly, cooperatively, and purposefully to ensure the availability of competitively priced natural gas.

The National Petroleum Council stands ready to work with government to further discuss the results of this report and to implement the recommendations in order to meet the nation's growing gas demand.

Respectfully submitted,

Joe B. Foster
NPC Chair

Foreword

The National Petroleum Council is pleased to report to the Secretary of Energy that, given immediate focus on key issues, natural gas can make an important contribution to the nation's increasing energy needs and its environmental goals through 2015 and beyond. The natural gas industry has evolved into a competitive industry offering its expanding and reliable services on a nationwide basis. Between 1990—the reference point for the 1992 NPC report—and 1998, total U.S. gas consumption grew from 19.3 trillion cubic feet (TCF) to an estimated 22 TCF and continues to represent approximately a quarter of the nation's fuel needs. Using the study methods described in this report, the Council concludes that gas demand is likely to increase to 29 TCF in 2010 and could increase beyond 31 TCF in 2015. Further, the resource base exists to support the indicated levels of future demand and adequate gas supplies can potentially be produced to meet that market. The additional supply required can be brought to market at competitive prices through an expanded network of pipeline, storage, and distribution facilities. However, the Council recognizes that meeting the significant challenges that accompany such vigorous market growth will require strenuous effort by the industry and substantial support on key issues by the government.

The initial impetus for the current study came from a letter dated May 6, 1998, in which then-U.S. Energy Secretary Federico Peña requested the National Petroleum Council to:

> Reassess its 1992 report [*Potential for Natural Gas in the United States*] taking into account the past five years' experience and evolving market conditions that will affect the potential for natural gas in the United States to 2020 and beyond. Of particular interest is the Council's advice on areas of Government policy and action that

would enable natural gas to realize its potential contribution toward our shared economic, energy, and environmental goals.

In making his request, the Secretary noted that "at least two major forces … are beginning to take shape which will profoundly affect energy choices in the future – the restructuring of electricity markets and growing concerns about the potentially adverse consequences that using higher carbon-content fuels may have on global climate change and regional air quality." Further, the Secretary stated that "For a secure energy future, Government and private sector decision makers need to be confident that industry has the capability to meet potentially significant increases in future natural gas demand." (See Appendix A for this letter and Secretary Bill Richardson's follow-up letter expressing his interest in receiving the Council's advice on these matters.)

To respond to this request, the Council established a 1998 Committee on Natural Gas under the Chairmanship of Peter I. Bijur, Chairman and Chief Executive Officer, Texaco Inc. T. J. Glauthier, Deputy Secretary of Energy, served as the Committee's Government Cochair, with H. Leighton Steward, Vice Chairman of the Board, Burlington Resources, Inc., and William A. Wise, President and Chief Executive Officer, El Paso Energy Corp., serving as Vice Chairs for Supply and for Transmission & Distribution, respectively. The Committee was assisted by a Coordinating Subcommittee, chaired by Rebecca B. Roberts, Strategic Partner, Global Alignment, Texaco Inc., with Robert S. Kripowicz, Principal Deputy Assistant Secretary, Fossil Energy, U.S. Department of Energy, serving as Government Cochair. (Appendix B contains the Committee roster along with the rosters of its Coordinating Subcommittee and three Task Groups on Demand, Supply, and Transmission and Distribution.)

KEY DIFFERENCES FROM 1992

The Secretary was correct in noting that the U.S. energy markets have changed significantly since the 1992 NPC study. The U.S. economy is growing more rapidly than anticipated in 1992, and with that growth has come a higher natural gas demand than was expected. Environmental regulations that favor natural gas consumption are more firmly in place than in 1992 and environmental restrictions on fossil fuel-burning facilities are increasingly stringent. In fact, gas demand has grown at a rate that exceeds even the most robust scenario projected in the 1992 study. Continued economic growth as well as concerns about air quality and climate change favor the continued expansion of natural gas demand.

Since 1992, the gas industry has undergone a significant restructuring. The primary impetus came from Federal Energy Regulatory Commission (FERC) regulations, which over time have converted interstate pipelines from sellers and transporters of natural gas to solely transporters. State regulators and local distribution companies (LDCs) are moving toward a similar result in many jurisdictions. This restructuring has driven changes in roles and risks for industry participants because a number of market functions and obligations formerly managed under the auspices of the LDCs and pipelines must now be accepted and carried out by other market participants. Since the 1992 study, new market structures—market hubs/centers, futures trading for natural gas, and a capacity release market (a secondary pipeline capacity market)—have either developed or matured. Other financial tools have been developed to reduce the risk of price change to buyers and sellers over extended time periods. In short, the gas market has become highly efficient and sophisticated, with numerous participants ensuring competitive prices. Increased confidence in the functionality of the gas market and in competitive gas prices has played a significant role in increasing gas demand.

The industry has benefited from remarkable progress in technology in areas that were not fully anticipated in 1992. For example, three-dimensional (3D) imaging now allows scientists to virtually "see" underground rock formations in graphic detail and to reduce drilling risk by more accurately predicting locations for hydrocarbon deposits. Progress in 3D and 4D seismic technology, in conjunction with imaging technology, has allowed producers to spot small hydrocarbon accumulations. Improved drilling techniques enable production companies to more precisely hit drilling targets and accomplish difficult maneuvers such as drilling a vertical well, turning a corner, and then drilling horizontally over five miles. New technology now allows producers to access supply in ocean waters that are more than a mile deep. These improvements, along with many more, have resulted in significant reserve additions and prospects of new production in areas that were once considered physically or economically unreachable.

Technological progress has also been evident in the transmission and distribution segments of the industry and has contributed to a steady and significant decline in transmission and distribution charges since the mid-1980s. Technological advances have taken place in areas such as gas measurement, pipeline monitoring, compression, and storage management. The dramatic improvements in information and communications technology have contributed to more efficient data management systems that support marketing activities and capacity scheduling. New end-use gas technologies, such as higher efficiency residential furnaces, natural gas cooling, and combined cycle power plants, continue to offer consumers higher efficiency, lower costs, and cleaner energy.

Although market confidence has grown and technology has improved the state of the industry, recent events have led to questions about the industry's ability to meet the demand growth potential. The downturn in world oil prices between late 1997 and early 1999 dealt a heavy blow to the exploration and production sectors of the U.S. gas industry, particularly to the oilfield supply/service contractors and the independent producers who supply over half of the nation's natural gas needs. Industry participants experienced an extended period of poor economic returns and, fearing a repeat of the 1984–89 depression in the industry, responded with significant downsizing and cutbacks in spending. Investment capital for developing new production, which for most industry participants is highly dependent on cash flow from crude oil and gas sales, declined dramatically in 1999. As a result, new supply development in the United States has slowed considerably. Although oil prices have now rebounded, these events have highlighted the boom and bust nature of the business and have made industry participants and investors very cautious.

Several other trends highlight the challenges that could impact the future of gas production and delivery. The broadening and extension of moratoria have reduced access to a portion of the nation's natural gas resource base. The economic hardship experienced by the oilfield supply/service sector has limited construction of rigs and other infrastructure, giving rise to questions on the industry's ability to respond to future drilling needs. Decreased spending on research and development raises concerns regarding future technological breakthroughs. Continued cutbacks and layoffs impair the industry's ability to attract new employees.

While these issues are significant, the Council wishes to emphasize that the industry has successfully met difficult challenges in the past and has proved to be resilient and resourceful. Each of the challenges identified in this study can be met if immediate, cooperative, and focused actions are taken by the industry and the government.

APPROACH TO THE 1999 STUDY

To conduct the study, the NPC Committee on Natural Gas appointed a Coordinating Subcommittee and three Task Groups to develop projections for gas demand, gas supply, and transmission and distribution. The primary focus of the study was to test supply and delivery systems against significantly increased demand. As in the case of the 1992 study, the Committee on Natural Gas selected Energy and Environmental Analysis, Inc. (EEA) to run econometric models for the analysis. The Coordinating Subcommittee and its Task Groups provided data and assumptions to EEA for inclusion in the development of a Reference Case for the focus period of 1999 to 2010. The assumptions used in the Reference Case represent a plausible view of the future and were selected with full understanding that, in reality, each could vary significantly. Each of the Task Groups developed sensitivity analyses to test the Reference Case through 2010 and to develop an extended view through 2015. The results of the Reference Case and the sensitivity analyses form a framework for better understanding the factors that influence supply and demand balances. This approach was particularly useful in exploring the potential range of outcomes beyond 2010, a point at which uncertainties in assumptions begin to escalate. Throughout this report, data are reported for the focus period of 1999 to 2010, with an extended view for the more uncertain period of 2011 through 2015. While the study did not attempt to model supply and demand beyond 2015, the issue of long-term sustainability is addressed.

The study participants focused on the broader industry implications and dynamics indicated by the data rather than attempt to forecast specific end results. Issues such as new regulations for climate change were not examined in detail, but other factors that increase demand were specifically analyzed and some correlations can be made. Changes that are occurring in the areas of electricity generation, such as distributed generation, were not studied, but the overall impact of increases in gas demand due to electricity generation were examined.

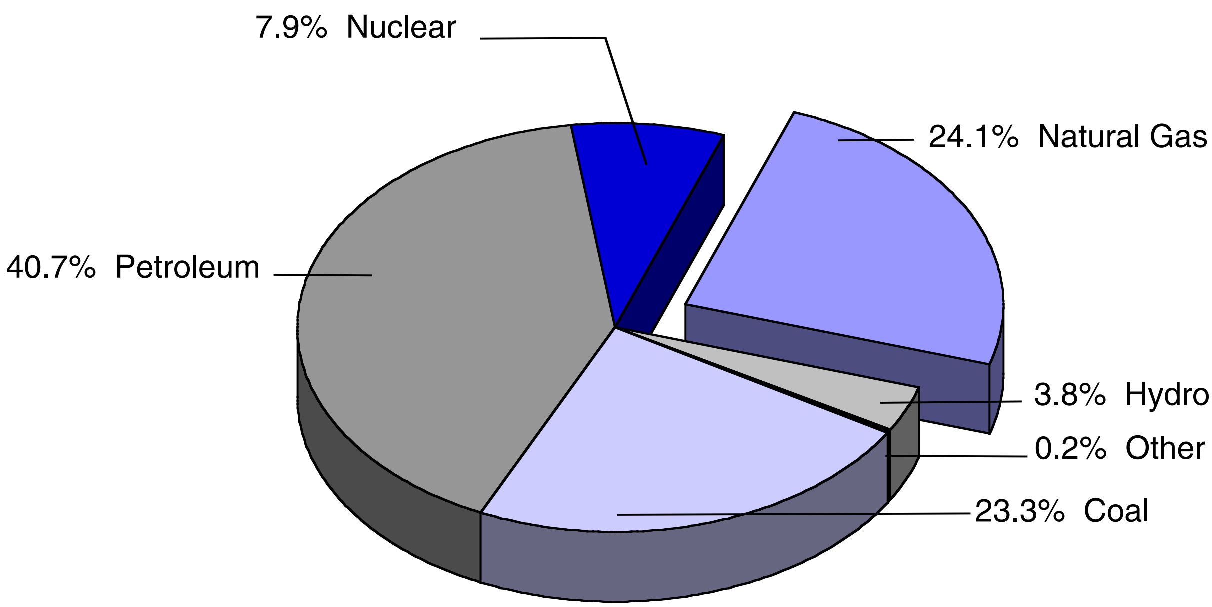
The National Petroleum Council believes that the results of the study, which are contained in this report, are amply supported by the rigorous analyses conducted by the Committee on Natural Gas and its subgroups. Further, the Council wishes to emphasize that the significant growth in demand that is projected in this study is based on long-term trends and should not be interpreted as a "goal" of the industry. However, as natural gas demand continues to expand, the natural gas industry stands ready to work with all stakeholders to economically develop the natural gas resources and infrastructure necessary for continuing the nation's economic growth and meeting its environmental goals.

Conclusions

The emphasis on natural gas is good news for the economy, the environment, and society as a whole. In recent years, the United States has enjoyed a thriving economy, which has been driven in part by the ready availability of energy at competitive prices. Natural gas has played a vital role in meeting those energy requirements and today provides almost a quarter of the nation's energy portfolio (Figure 1). As this study demonstrates, natural gas can be a growing source of energy to power our economy for many years to come.

Actual U.S. gas demand has outpaced the 1992 study High Reference Case projection by more than 1 TCF over the period from 1990 through 1998 (Figure 2). This 1999 study now projects that U.S. gas demand will grow from 22 TCF (including net storage fill) in 1998 to approximately 29 TCF in 2010 and could rise beyond 31 TCF in 2015. Each key consumption sector—residential, commercial, industrial, and electricity generation—will increase (Figure 3a). However, the electricity generation sector alone will account for almost 50% of the increase through 2010 (Figure 3b). Over 110 gigawatts of new gas-fired generation capacity is projected to go into service by 2010, and a total of 140 gigawatts by 2015. Natural gas is now the preferred fuel for new electricity generation facilities, with 96% of the more than 200 recently announced new generation projects planning to burn natural gas. This dramatic shift to natural gas is driven by improved efficiencies, lower capital costs, reduced construction time, more expeditious permitting of natural gas-burning facilities, and environmental compliance advantages. However, the service requirements and price sensitivity of this additional load present many challenges to suppliers and transporters of natural gas.

Figure 1. Total U.S. Energy Consumption
By Primary Energy Source, 1998

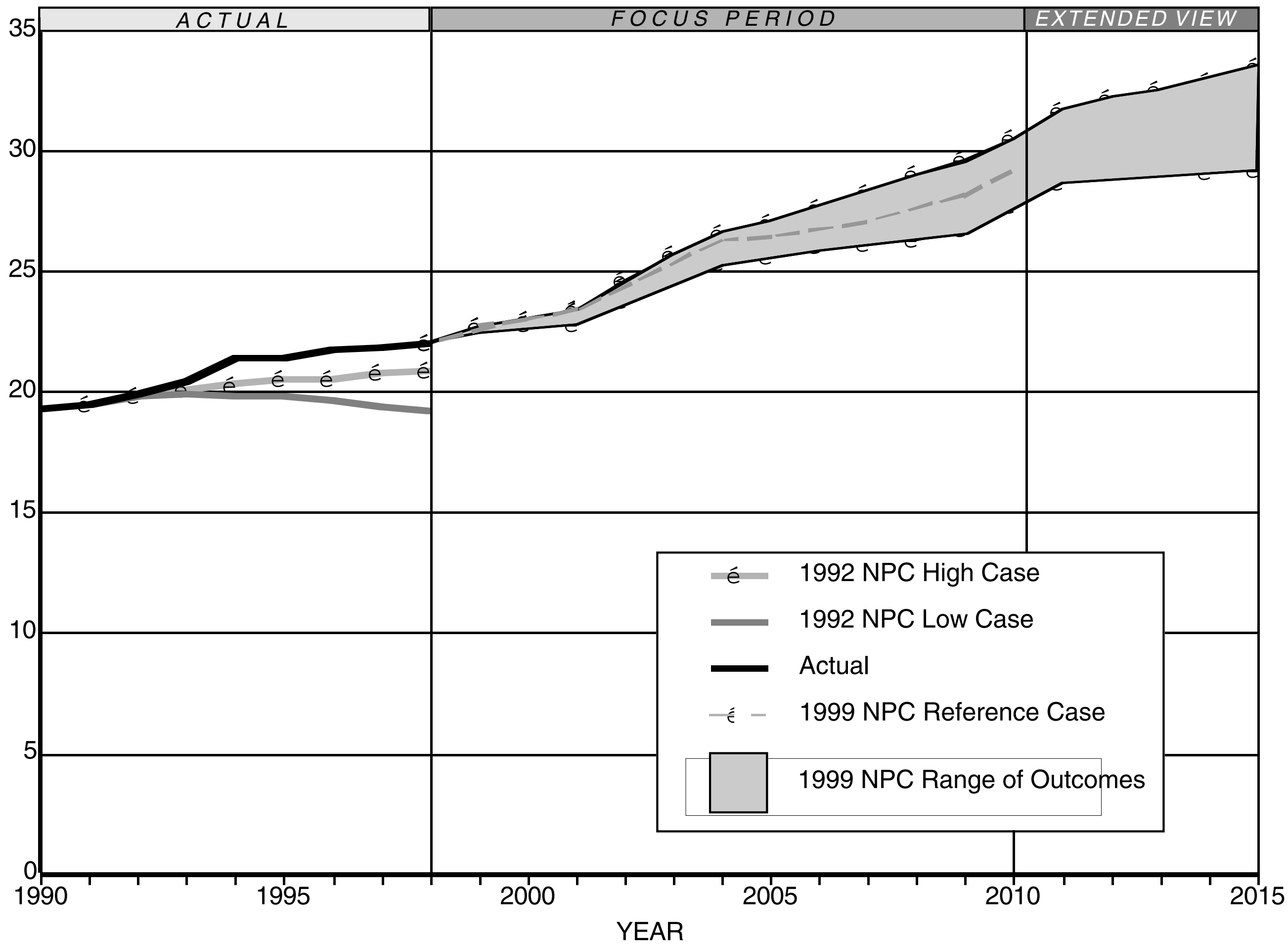


Source: DOE/EIA, Monthly Energy Review, September 1999

- Natural gas supplies almost a quarter of the nation's energy needs.

Figure 2. U.S. Natural Gas Demand

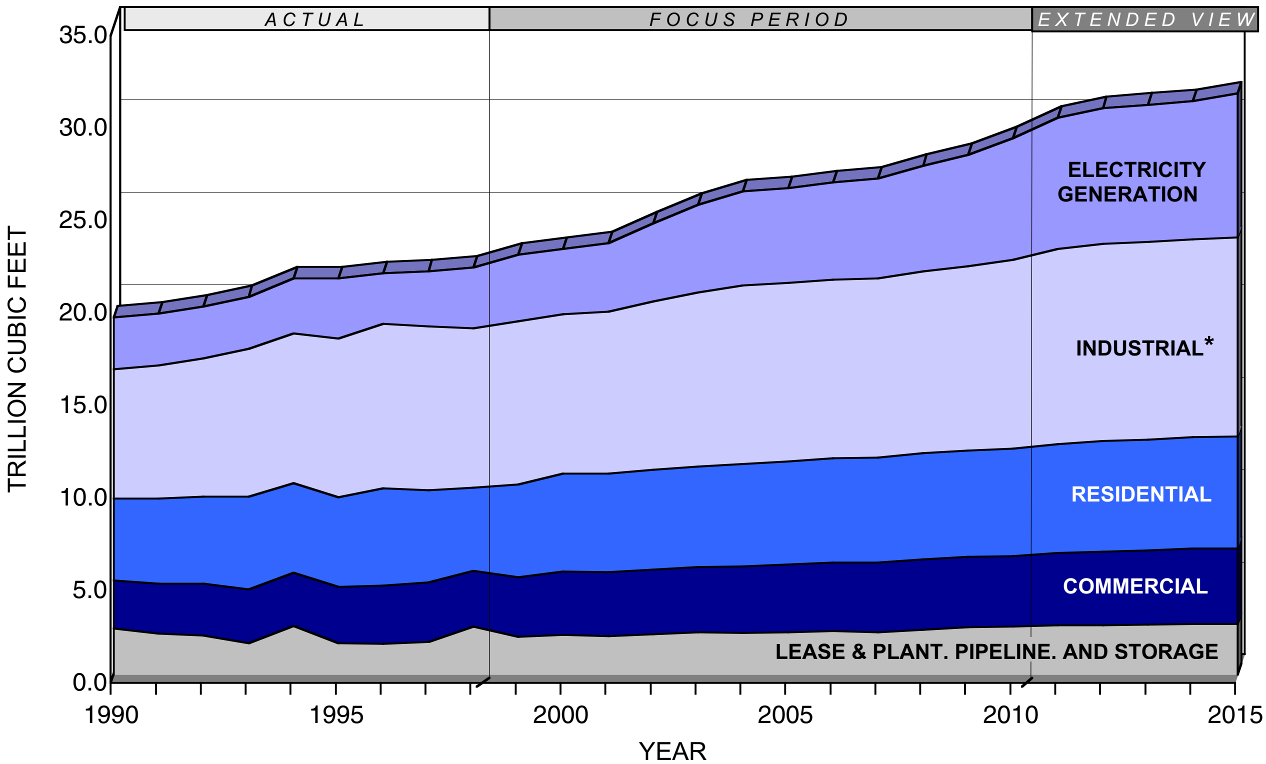
Comparison of 1992 and 1999 NPC Study Results



- Demand has exceeded the 1992 high case projection.
- Demand growth is expected to increase to 29 TCF by 2010, and increase beyond 31 TCF by 2015.
- Additional 7 TCF/year of gas supply will be needed by 2010.

Source of historical data: DOE/EIA, Natural Gas Monthly, September 1999

Figure 3a. U.S. Natural Gas Demand By Sector

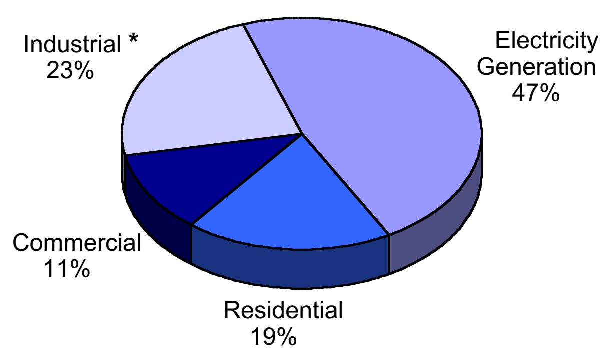


- Demand will grow in all sectors.

- Almost 50% of demand growth will be due to electricity generation.

Figure 3b. Growth in Reference Case Demand, 1998–2010

(Distribution of 7 TCF Increase by Sector)



** Historical data include all gas use for industrial cogeneration and independent power producers; all gas for new power plants except cogeneration is included in the electricity generation sector.*

Source: DOE/EIA, Natural Gas Monthly, September 1999

Growth in gas demand will remain subject to changes in such key variables as growth in the economy, price of competing fuels, nuclear retirements, and the capacity utilization of coal-fired electricity generation plants. For example, if 30 gigawatts of nuclear capacity are retired rather than the 15 gigawatts assumed in the Reference Case, demand could increase another 0.7 TCF. If coal capacity utilization remains at current levels instead of increasing from 64% to 75% as assumed in the Reference Case, demand could rise as much as 1.7 TCF. New environmental regulations, beyond those that are currently scheduled for implementation, have not been factored into this analysis and could also further increase natural gas demand. While this study did not attempt to quantify the impacts of additional environmental regulations on demand, incremental increases from Kyoto-related regulation were estimated in independent studies at 2–12% by the Energy Information Administration and 10–22% by the Edison Electric Institute beyond their respective reference cases.

The role that natural gas plays in improving the nation's environment has been widely recognized. A recent Minerals Management Service (MMS) report, *OCS Resource Management and Sustainable Development* (September l999), pointed out the benefits of natural gas:

> Natural gas is the least polluting fossil fuel. It is thought by many, including the present administration, to be the fuel of the early part of the next century that will power our economy into the sustainable fuels of the later decades and beyond. Even in the short run, conversion of more of our fuel burning facilities to natural gas will greatly diminish air pollution and improve the long run sustainability of forests, waters, and farmlands now being negatively affected by acid deposition.

The MMS report also noted the following regarding income from offshore resources:

> …royalties and taxes enable government to carry on programs which are beneficial to the oil and gas industry as well as society as

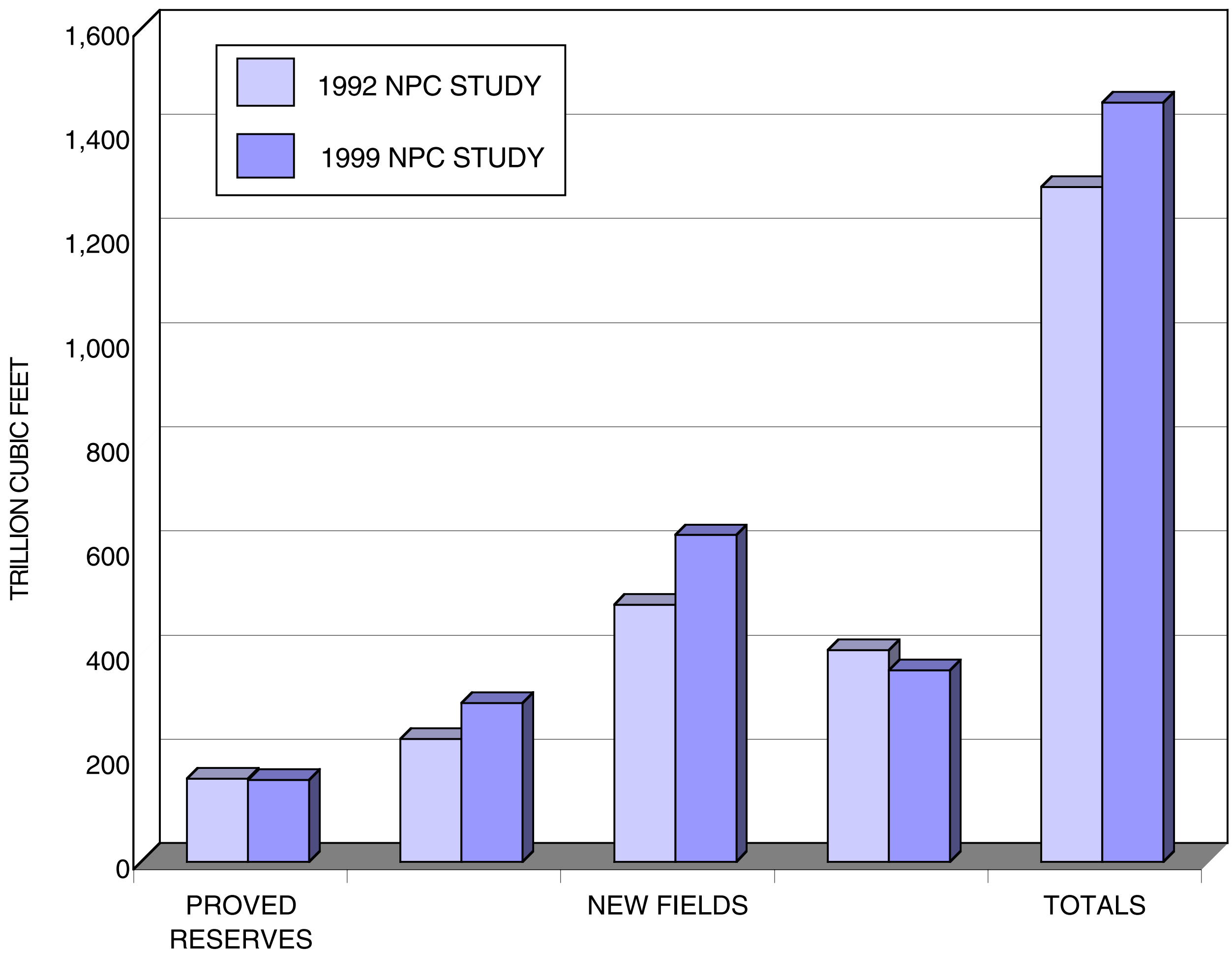
a whole. For example, an average of 60 percent of the collections from Federal offshore sources [$126 billion since offshore leasing began in 1953] went into the U.S. Treasury General Fund. Among other expenditures the Government uses a portion of these funds to invest in social infrastructure, which helps make the U.S. economy one of the most productive in the world. One of the areas in which some of this money is invested is in renewable energy, including many forms of energy conservation.

In onshore areas, federal, state, and local governments receive royalty income and collect taxes from natural gas production. The revenues that are collected from these sources allow these entities to provide essential services expected by their citizens, such as funding for education.

This study estimates the U.S. natural gas resource base, excluding Alaska, to be 1,466 TCF (Figure 4). This total represents a net increase of 171 TCF over the 1,295 TCF estimated in the 1992 study. Taking into account the 124 TCF that has been produced in the lower-48 states since then, the estimate of the resource base has increased 23% since the last study. The increase is largely due to technology breakthroughs that have opened new frontiers such as the deepwater Gulf of Mexico and have provided improved information and better tools for evaluating—and more fully recovering—resources.

U.S. gas demand will be filled with U.S. production, along with increasing volumes from Canada and a small, but growing, contribution from liquefied natural gas (LNG) imports (Figure 5a). Two regions—deepwater Gulf of Mexico and the Rockies—will contribute most significantly to the new supply (Figure 5b). U.S. production is projected to increase from 19 TCF in 1998 to 25 TCF in 2010, and could approach 27 TCF in 2015. Deeper wells, deeper water, and nonconventional sources will be key to future supply. For example, deepwater production (water depths greater than 200 meters), which in 1998 provided 0.8 TCF annually, will increase to over 4.5 TCF in 2010 (Figure 6). Onshore production from nonconventional formations is projected to increase by 50% from 4.4 TCF in 1998 to almost 7 TCF in 2010, with much of it coming from

Figure 4. U.S. Lower-48 Natural Gas
Resource Base Estimates
Comparison of 1992 and 1999 NPC Study Results

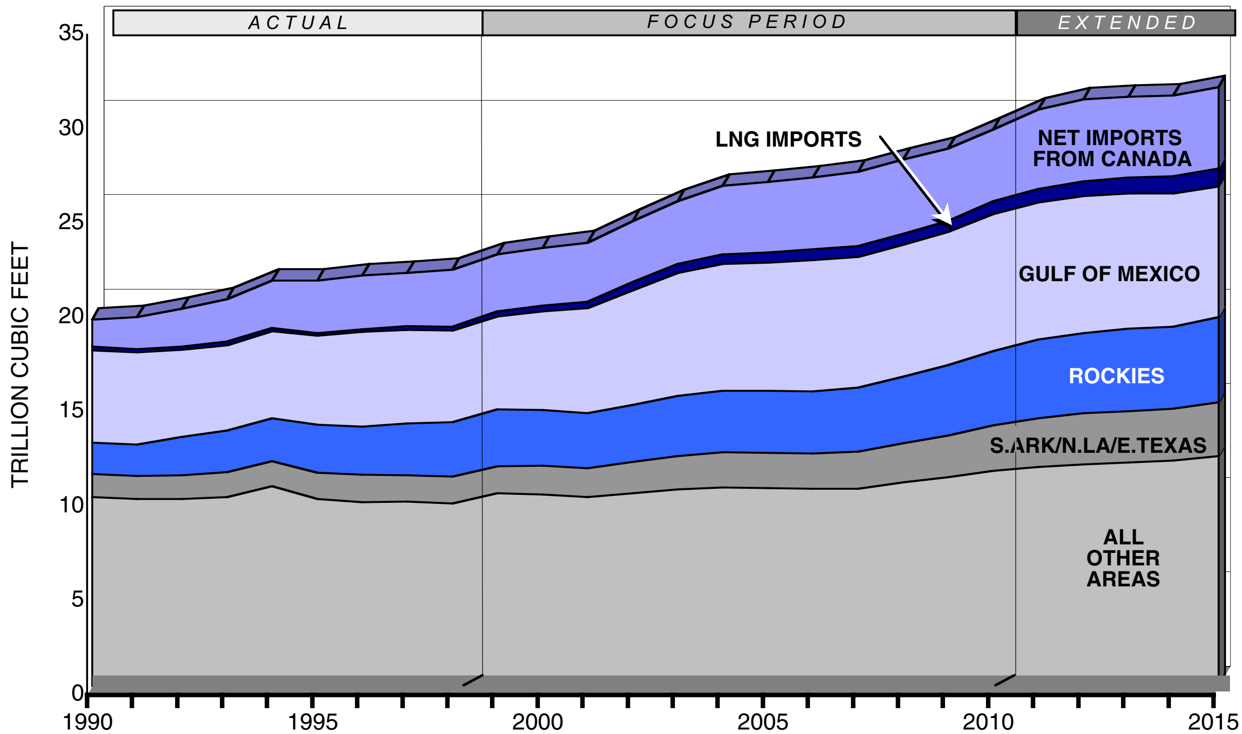


- Estimate of remaining resource base has grown 171 TCF to 1,466 TCF.

- Resource base estimate increased 23%, considering 124 TCF of production.

- Growth is primarily from New Fields, especially in deep water.

Figure 5a. U.S. Natural Gas Supply By Source

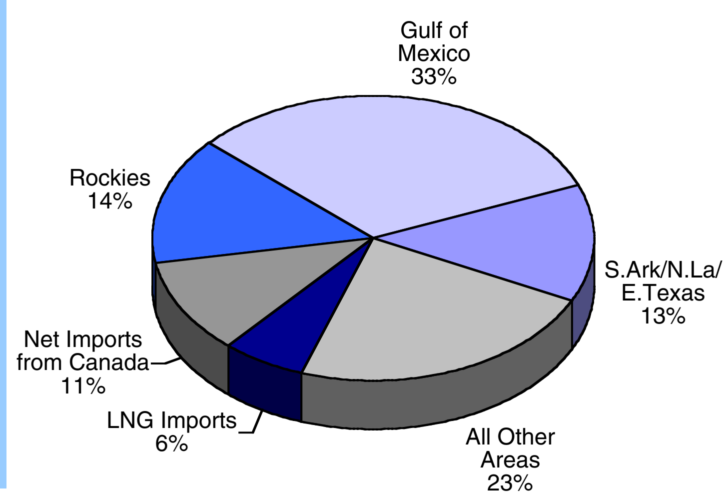


NOTE: Total does not net out exports to Mexico.

- Natural gas demand will be met primarily with domestic resources.
- Highest growth in U.S. production will be from Gulf of Mexico and Rockies.
- Canada will continue to be an important source of supply.

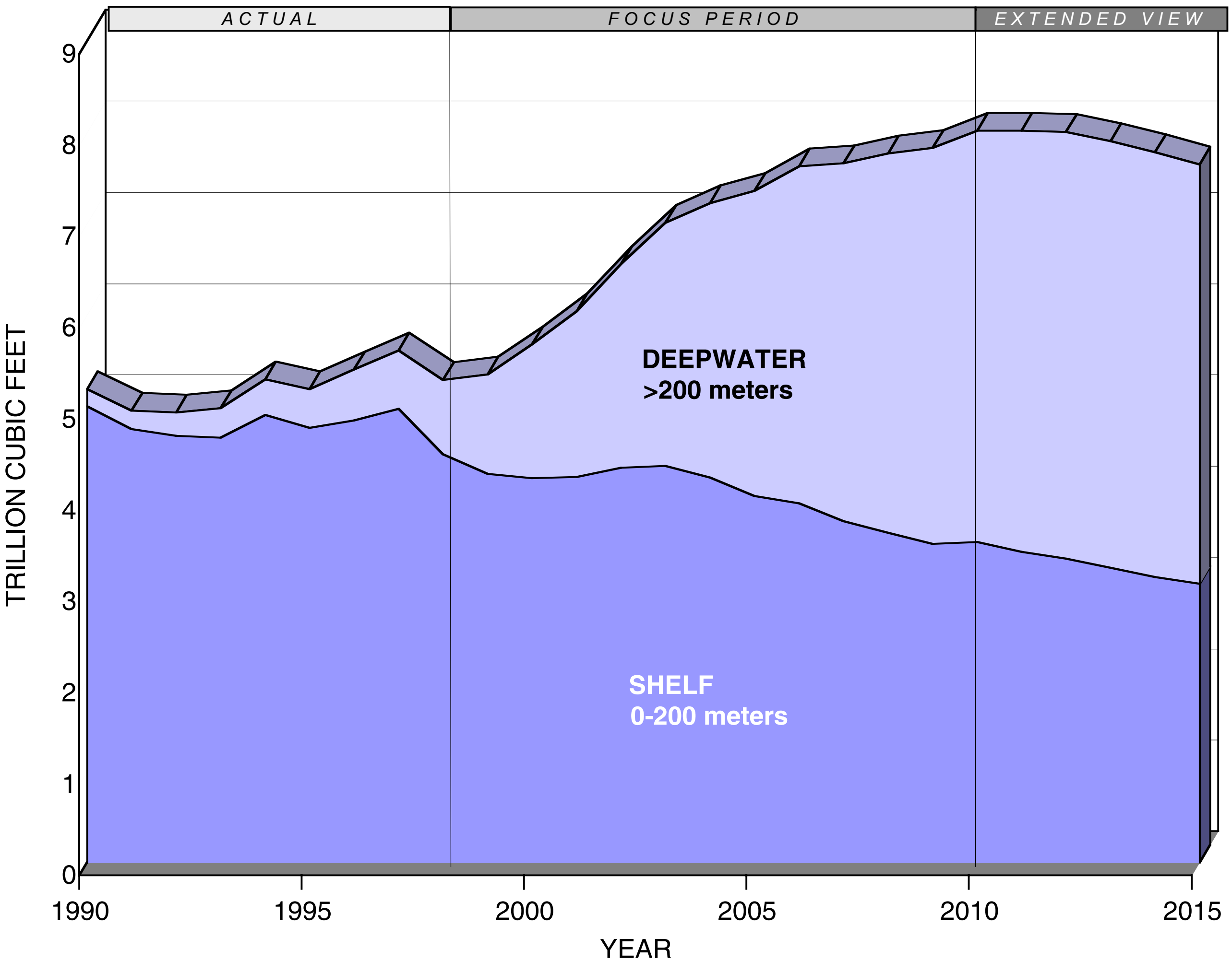
Figure 5b. Growth in Reference Case Supply, 1998–2010

(Distribution of 7 TCF Increase by Source)



Source of historical data: DOE/EIA, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves Annual Reports, 1990–1997

Figure 6. U.S. Gulf of Mexico Natural Gas Production



- Gulf of Mexico production increases by 2.7 TCF by 2010.
- Deepwater production increases from less than 1 to over 4.5 TCF/year.
- Gradual decline is projected for shelf production.

Source of historical data: Dwights/PI production reports, June 1999 the Rocky Mountain region. By 2015, nonconventional gas production could be approaching 9 TCF. Production is likely to decrease in more traditional areas such as the Gulf of Mexico shelf and onshore Louisiana, each dropping by roughly one-third by 2015. It is important to note that approximately 14% of current natural gas supply is "associated," meaning that it is produced from oil wells. This associated gas will continue to be an important component of the overall supply, particularly in deepwater Gulf of Mexico.

Imports from Canada are projected to increase from 3 TCF in 1998 to almost 4 TCF by 2010, continuing to represent 13–14% of U.S. demand. Canada's remaining resource base is estimated at approximately 670 TCF in this study, down from 740 TCF in 1992. The decrease in the estimated Canadian resource base is due to depletion and reassessment of the nonconventional resources. Challenges similar to those confronting the U.S. industry will be faced by the Canadian producers, compounded by the fact that much of this gas is in frontier areas such as the MacKenzie Delta in far northwest Canada. Reaching this frontier will require significant capital expenditures as well as considerable lead times. Continued cooperation between the United States and Canada will be essential to ensure the timely availability of Canadian gas.

LNG imports are projected to reach a maximum of approximately 0.9 TCF, based on a 75% average capacity utilization rate for existing facilities. The assumption was made that no additional LNG import facilities would be built in the 1999–2015 period. Also, the assumption was made that exports to Mexico would reach a maximum of 0.4 TCF to serve Mexico's gas demand near the U.S. border.

The infrastructure required to deliver gas to market must be optimized and expanded to accommodate the increase in demand as well as the changing logistics of getting new supply to new customers. Future needs include new pipelines to reach supplies in the frontier regions, expansion of existing pipeline systems, new laterals to serve electricity plants, and expansion and construction of storage facilities to meet seasonal and peak-day requirements. By 2015, more than 14 million new customers will be added to the natural gas delivery system. To serve this growing market through 2015, over 38,000 miles of new transmission line are projected to be needed as well as 263,000 miles of distribution mains and almost 0.8 TCF of new working gas storage capacity.

The current delivery system (transmission, distribution, and storage) was built and optimized over decades to meet the design peak-day requirements of firm service customers that were primarily residential, commercial, and to a lesser extent, industrial customers. The anticipated growth in electricity generation demand for natural gas will require the delivery system to be re-optimized to meet larger off-peak swing loads as well as peak-day requirements that will increase from 111 BCF per day in 1997 to over 152 BCF per day in 2015. Meeting requirements of the electricity generators on a significantly larger scale will entail changes in operational procedures, communications, tariffs, and contracting. Further, these changes must be accomplished without degrading the historically reliable service to the residential, commercial, and industrial markets.

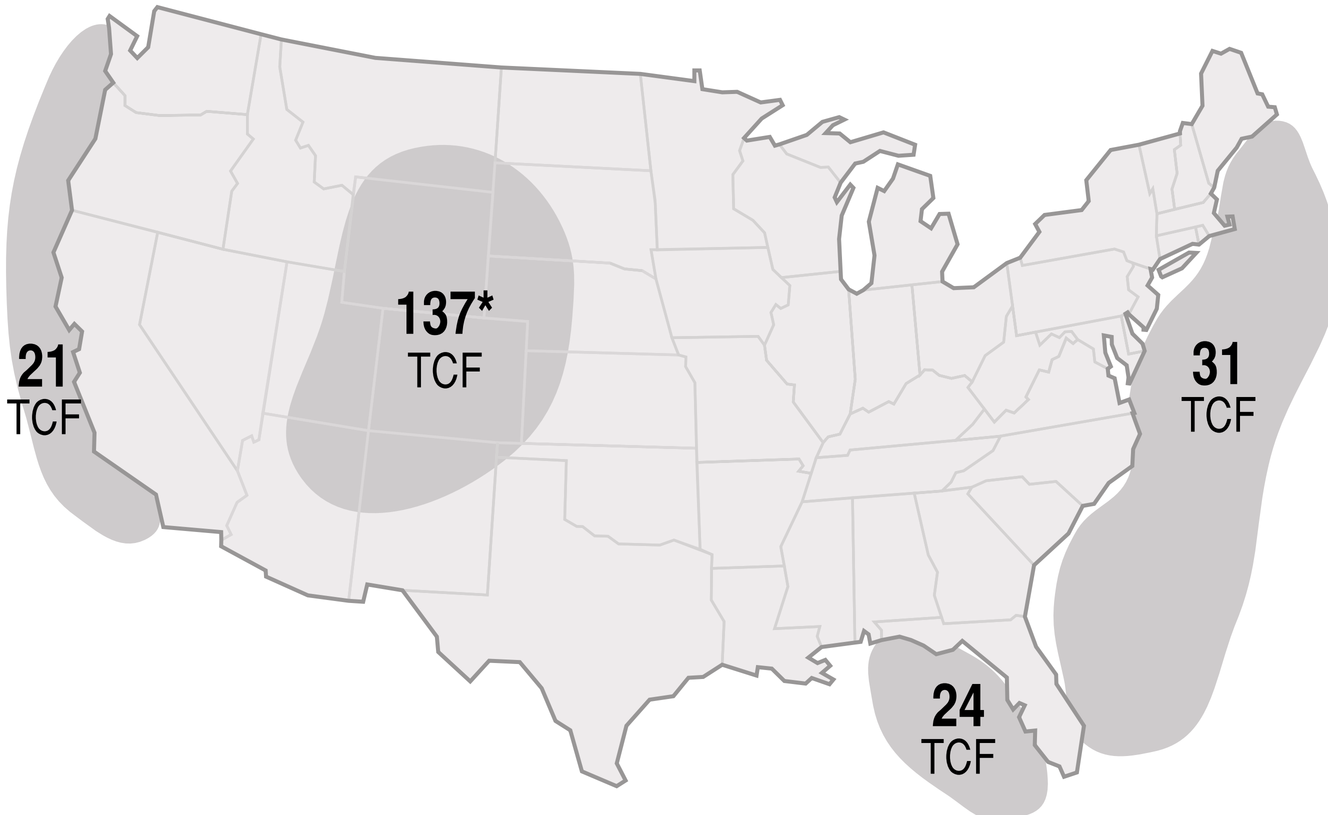
The Council believes that an unprecedented and cooperative effort among industry, government, and other stakeholders will be required to develop production from new and existing fields and build infrastructure at sufficient rates to meet the high level of demand indicated in this study. The ability to meet the anticipated demand hinges on addressing the following critical factors: access, technology, financial requirements, skilled workers, drilling rigs, lead times, and changes in customer requirements.

CRITICAL FACTORS

Access

Much of the nation's resource base resides on federal lands or in federal waters, yet a large portion of this resource base is not open to either assessment or development (Figure 7). Two of the most promising regions for future gas production, the Rocky Mountains and the Gulf of Mexico, currently have

Figure 7. U.S. Lower-48 Natural Gas Resources Subject to Access Restrictions



* *Approximately 29 TCF of the Rockies gas resources are closed to development and 108 TCF are available with restrictions.*

- Significant amount of resource is subject to access restrictions.
- These areas are close to large and growing population centers.

significant access restrictions. For example, an estimated 40%—or 137 TCF—of potential gas resource in the Rockies is on federal land that is either closed to exploration or is open under restrictive provisions. Another 76 TCF of resources are estimated for restricted offshore areas in the eastern Gulf of Mexico, the Atlantic, and the Pacific. The eastern Gulf of Mexico is largely closed to exploration and the limited areas that are now open are the subject of political debate. The proposed Lease Sale 181 scheduled for December 2001 in the eastern Gulf of Mexico is the first such sale in this area since the late 1980s, yet only covers a small portion of the entire area. The East Coast of the United States is completely closed to development while Canada is pursuing its East Coast gas resources, as demonstrated by the recent Sable Island development off the coast of Nova Scotia. In addition, drilling on the West Coast of the United States also faces strong restrictions, while offshore British Columbia is opening up to greater exploration and production.

This study assumes that planned lease sales for areas in the Outer Continental Shelf (OCS) will continue on schedule and that further restrictions will not be applied to those lands currently open to development. These assumptions may be optimistic in light of recent statements by some public officials. Further restrictions would increase the challenge of meeting the projected gas demand with cost-competitive supply. Conversely, opening hydrocarbon-rich areas for development would greatly improve the industry's potential to respond to market needs.

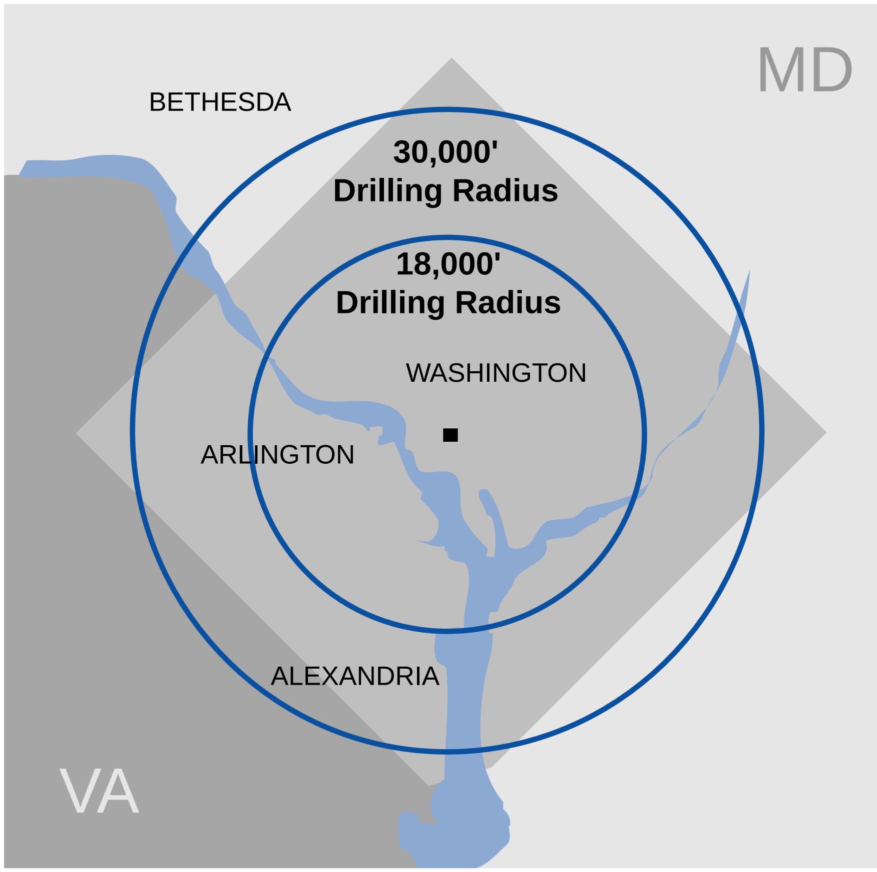
Access is also an issue for the transmission and distribution sectors of the industry as they seek rights of way for pipeline facilities. The permitting and construction processes have become more complex over time. Restrictions for wetlands, wildlife refuges, and other sensitive federal and state lands impact the routing and construction of pipelines throughout the United States, not just the frontier areas. Other issues arise from the encroachment of urban development on existing rights of way, heightened community awareness of and resistance to pipeline construction, and increasingly restrictive government policies and regulations. Resolution of these issues—which must be addressed for each pipeline addition—is costly and time-consuming and often results in project delays or abandonment of projects.

Most of the access restrictions are due to environmental concerns or multiple-use conflicts even though industry has made tremendous improvements in reducing the "footprint" of exploration, production, and transportation activities, and in maintaining clean, safe operations. As stated in a recent Department of Energy report, "Resources underlying arctic regions, coastal and deep offshore waters, sensitive wetlands and wildlife habitats, public lands, and even cities and airports can now be contacted and produced without disrupting surface features above them."[1] An excellent example of the dramatic improvements in environmental footprints can be found in Alaska where significant efforts have been made to minimize the impact of drilling operations on the tundra. A report to the Secretary of the Interior in 1997 by the Alaska Oil and Gas Association stated that in the 1970s, pads for drilling operations took up about 65 acres whereas the pads for recent operations are now less than 10 acres. The report further explained that cluster drilling and extended reach drilling enable producers to access hydrocarbon deposits 3–4 miles away from the pad, thus greatly reducing the number of drilling locations and associated roads and pipelines. Lateral extensions of 18,000 feet are common on the Alaskan North Slope today. More recent efforts in other parts of the world have extended the drilling reach to 5–6 miles. This has the same effect as setting up drilling operations on the White House lawn and extracting hydrocarbons from beneath most of Washington, D.C., and into its suburbs (Figure 8).

Equally impressive improvements in environmental impacts have been demonstrated offshore, where much of the natural gas production is associated with oil production. As reported to President Clinton by the Cabinet in *Turning to the Sea: America's Ocean Future* (September 1999), "Advances in technology have made offshore oil and gas production cleaner and safer than ever. Since

[1] U.S. Department of Energy, Office of Fossil Energy, *Environmental Benefits of Advanced Oil and Gas Exploration and Production Technology*, October 1999, pg. 13.

Figure 8. Reducing Environmental Impact
with Extended-Reach Drilling.



- Improvements in extended-reach drilling allow access to resources 5 to 6 miles from the drilling site.

- Similar technologies for minimizing environmental impact continue to be developed.

1980, 6.9 billion barrels of Outer Continental Shelf oil have been produced with a spillage rate of less than 0.001%. Despite these advances, however, environmental concerns have led to congressional and executive moratoria since 1981, and many of our coastal areas are now closed to new leasing through the year 2012."

This study has determined that access issues, and associated environmental concerns, must be addressed. Access to some portion of the federal gas resource base currently closed or significantly restricted to appraisal or development, as well as acquisition of rights of way, is essential to meeting the projected demand with cost-competitive gas supply.

Technology

Even though the estimated resource base is adequate to last many decades, technological challenges and the degree of difficulty in reaching, evaluating, and producing the resource base continue to escalate. The previously referenced report by the Office of Fossil Energy of the U.S. Department of Energy [2] highlights the importance of research and development to the oil and gas industry:

> In the past three decades, the petroleum business has transformed itself into a high-technology industry. Dramatic advances in technology for exploration, drilling and completion, production, and site restoration have enabled the industry to keep up with the ever-increasing demand for reliable supplies of oil and natural gas at reasonable prices. The productivity gains and cost reductions attributable to these advances have been widely described and broadly recognized… Looking forward, the domestic oil and gas industry will be challenged to continue extending the frontiers of

[2] Ibid, p.1.

technology. Ongoing advances in E&P productivity are essential if producers are to keep pace with steadily growing demand for oil and gas, both in the United States and world wide. Continuing innovation will also be needed to sustain the industry's leadership in the intensely competitive international arena, and to retain high-paying oil and gas industry jobs at home. Progressively cleaner, less intrusive, and more efficient technology will be instrumental in enhancing environmental protection in the future.

Technology improvements are particularly important given the more difficult conditions accompanying new resources. Deeper wells encounter extreme temperatures and pressures and increased potential for intensely corrosive environments. These conditions require high-strength materials and advanced drilling methods. Current deepwater endeavors involve exploration wells in over 8,000 feet of water and complex production projects in more than 5,000 feet of water. Subsea pipelines must be built to withstand powerful currents, shifting ocean floors and external pressures that are greater than those inside the pipe. Innovative design, fabrication, and installation techniques must emerge to enable these new resources to reach existing markets at attractive prices.

Technology improvements are also needed for expanding and managing the delivery system and improving efficiency at the burner-tip. The increased challenges of serving a growing market and changing load must not jeopardize the historical reliability and favorable economics of the transmission and distribution system. Pipelines and LDCs will continue to rely on technology for reducing operation and maintenance expenses and minimizing environmental impacts of facilities construction. Information and communications technology will play an ever-increasing role in safe and efficient operations as well as in supply management and customer service enhancements.

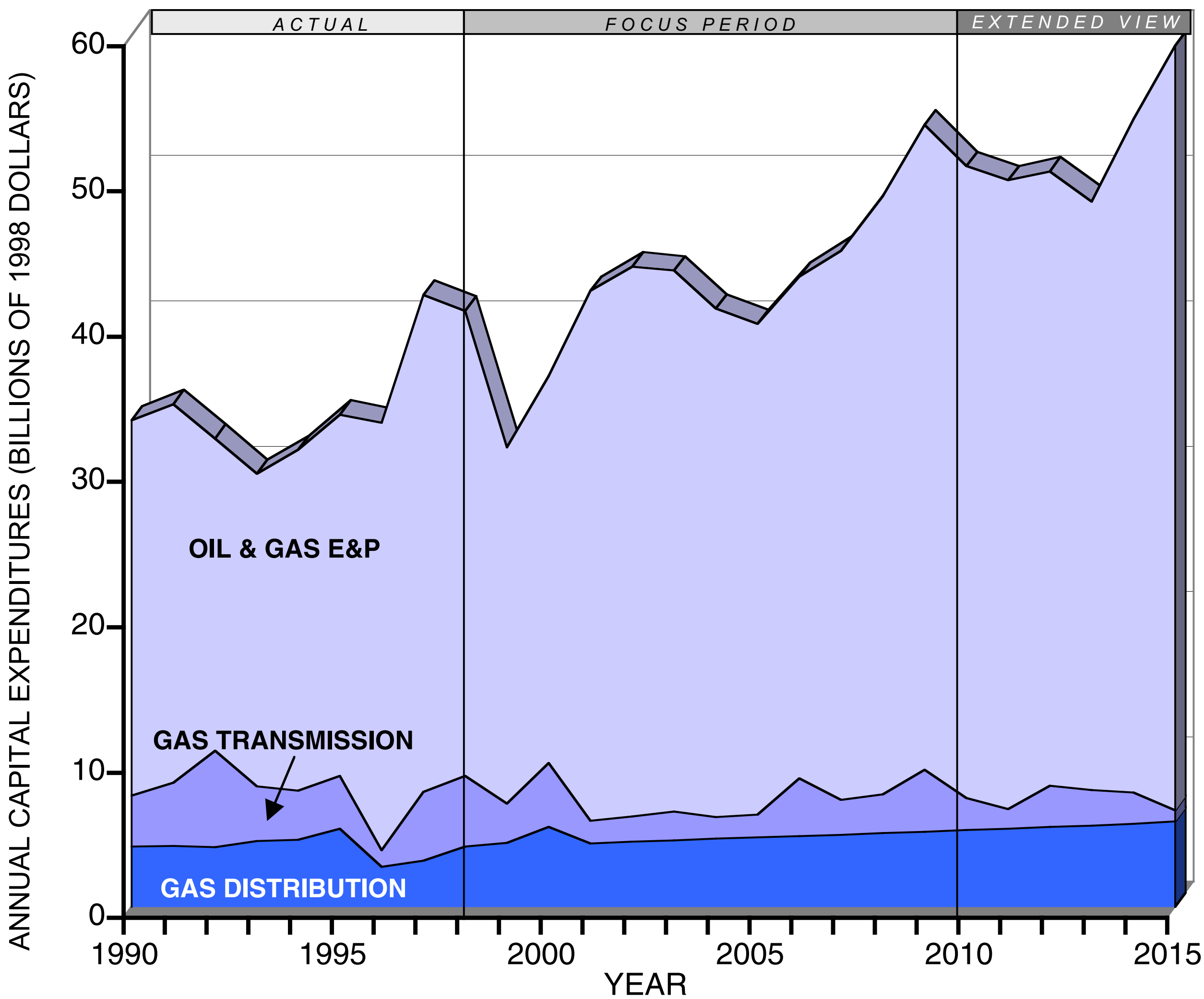
Technology advances are essential in all industry segments for improving operational efficiencies, reducing resource development time, increasing production, developing frontier areas, controlling costs, and minimizing environmental impact. This study assumes that technology improvements will continue at an aggressive pace. However, recent industry trends in research and development spending have raised concerns regarding this assumption. Industry restructuring, consolidations, and spending cuts have resulted in reductions in research budgets. Producers are turning to the service sectors to develop new technology for specific applications. Industry consortia have been formed to address critical technology challenges such as deepwater development. While many of these changes improve the efficiency with which research and development dollars are spent, concerns have been widely expressed that basic and long-term research are not being adequately addressed.

Financial Requirements

Adequate financial performance must be demonstrated in order to compete for and attract the investments required to meet the growing demand. Companies will need to balance short-term performance demands with long-term planning to achieve the needed growth. Almost $1.5 trillion ($1998) will be required to fund the industry through 2015. This amount includes over $700 billion for operating expenses and an estimated $781 billion for capital investments. Approximately $658 billion of capital is projected to be spent for oil and gas supply development and about $123 billion for transmission, storage, and distribution infrastructure expansion (Figure 9). This equates to an average annual increase in capital expenditures from $34 billion per year between 1990 and 1998 to $46 billion between 1999 and 2015. Many of these expenditures will involve higher risk projects—such as large deepwater projects or pipelines to new frontiers—each of which can easily exceed $1 billion.

While much of the required capital will come from reinvested cash flow, capital from outside the industry is essential to continued growth. To achieve this level of capital investment, industry must be able to compete with other investment opportunities. This poses a challenge to all sectors of the industry, many of which have historically delivered returns lower than the average reported for Standard and Poors 500 companies.

Figure 9. Capital Required for Expansion



** Because "associated" natural gas is produced with oil, expenditures for oil and gas have not been separated.*

- Substantial increase in capital expenditures will be required.
- Total capital expenditures for 1999–2015 will be $785 billion.

Source of historical data: AGA Gas Facts–1998, and estimates from EEA, Inc.

The transmission and distribution sectors of the industry also face challenges in attracting investments to future projects. Expanding the infrastructure of the delivery system to accommodate increased demand and changing requirements of new customers will involve changes in financial risks. For example, expiring long-term LDC contracts for pipeline capacity, which historically provided the financial backing for pipeline expansions, will be replaced by shorter term contracts with new non-utility customers. Uncertainty exists with future rate structures and obligations to serve, as electricity and gas restructuring continues. Industry participants and regulators must work together to find an appropriate balance for these risks so that the needed infrastructure expansions can be accomplished.

Skilled Workers

A significant concern of the industry is the future availability of skilled workers at all levels to produce the increased supply and construct the necessary infrastructure. Company consolidations and volatile fluctuations in oil prices have resulted in cuts in exploration and production budgets, leading to layoffs at all levels in exploration and production companies and in service/supply companies. Approximately 500,000 jobs have been eliminated from the industry since the early 1980s, with over 40,000 job cuts occurring in the producing sector alone in the past year. Simultaneous reduction in industry hiring rates in the last 20 years has resulted in a disproportionate percentage of the workforce reaching retirement age in the next decade—an average of 40% in a sampling of major producers. Furthermore, the next generation of workers is not choosing to enter the industry, as indicated by the significant decrease in enrollment in some energy-related college curricula since the mid-1980s. The oilfield service/supply sector faces a similar situation as many laborers and supervisory personnel have left the industry in search of more stable work. Higher wage scales are likely to be required to attract workers back into the industry.

Drilling Rigs

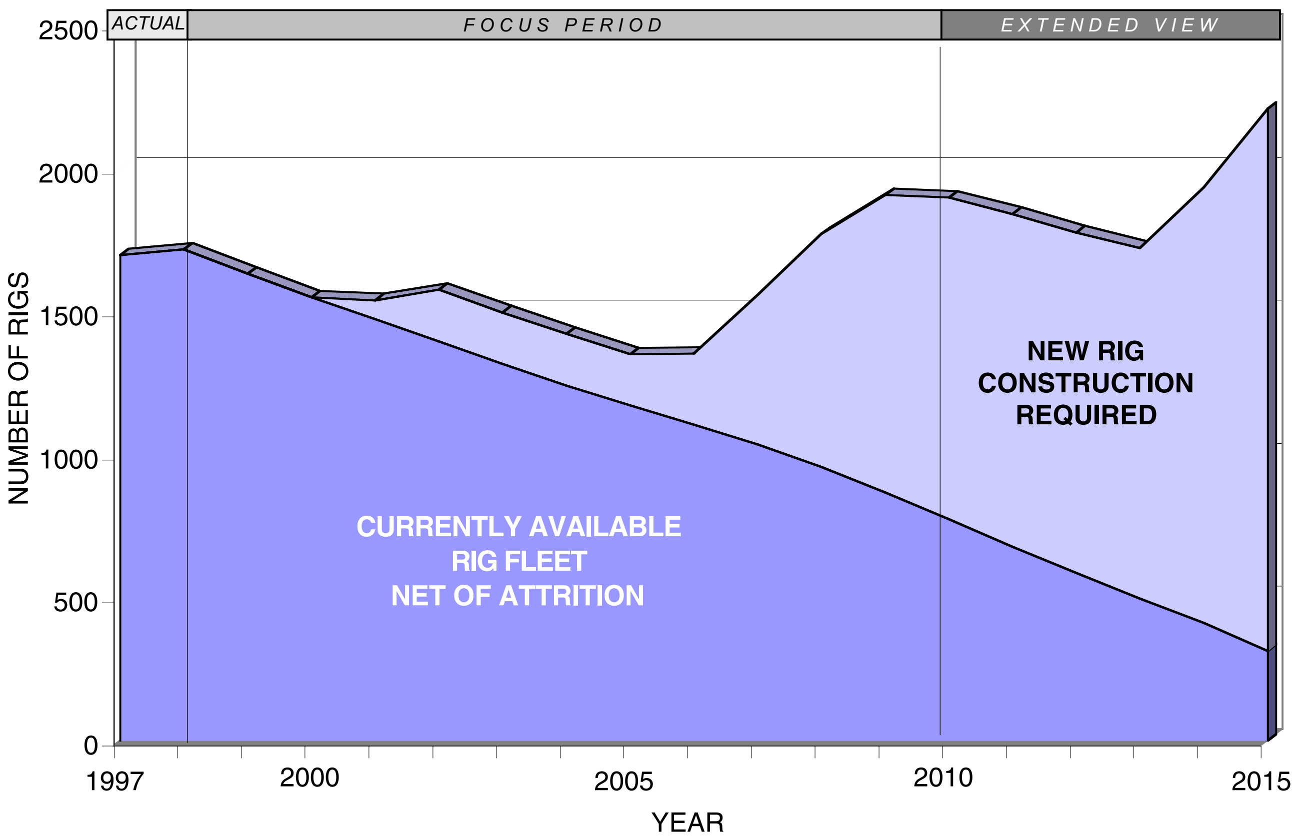
The U.S. drilling fleet must expand to undertake the dramatic increase in activity that will be required over the next decade to produce the additional supply. The total number of oil and gas wells drilled per year (including dry holes) will have to double, from approximately 24,000 in 1998 to over 48,000 by 2015. Even taking into account anticipated improvements in drilling efficiencies, approximately 2,300 active rigs (over 2,100 land rigs and 180 offshore) would be needed to achieve this level of drilling. This represents an 80% increase over the 1,250 average active rig count estimated for 1999.

Rig availability, which is crucial to exploration and development, will be a challenge for the industry. The oilfield supply and service sectors have been hit particularly hard by the boom and bust cycles. Very few new onshore drilling rigs have been built since the mid-1980s. If the 5% per year historical attrition rate were to continue, most of the existing 1,700 onshore rigs would be retired by 2015 and a total of almost 1,900 onshore rigs would have to be built (Figure 10). Additions to the offshore rig fleet will also be needed and are projected to include 10 deepwater drilling rigs, 32 platform rigs, and 30 jack-up rigs and barges (Figure 11). Although the number of new offshore rigs is smaller, the average cost per rig is significantly higher than that of onshore rigs. The drilling sector and the manufacturers of drilling equipment are not currently positioned to undertake this level of expansion.

Lead Times

Reduction of development lead times—from lease acquisition and prospect identification, to the beginning of exploration, to pipeline construction for delivery to the burner tip—is critical to meeting the gas demand projected in this study. For example, as many as 10 years—or two-thirds of the time period of this study—may elapse between the time a block in the offshore is leased until production flows to market. Industry and government are working diligently to reduce development time by streamlining processes and applying new technology. However, access limitations and cumbersome permitting and approval

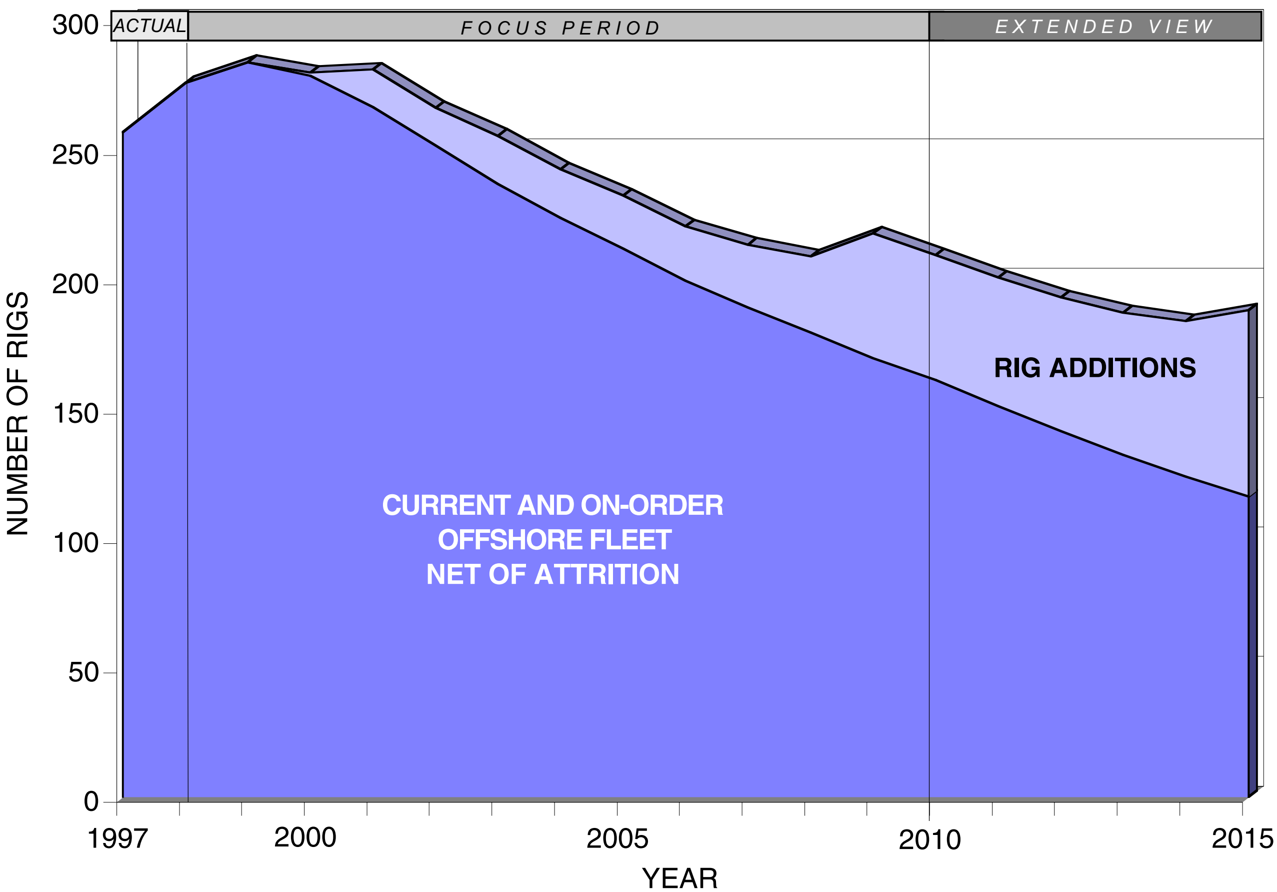
Figure 10. Onshore Drilling Rig Fleet



- 1,900 new onshore rigs will be needed through 2015, as the number of wells drilled per year doubles.
- Very few onshore rigs have been built since the 1980s.
- Availability of skilled workers to build and operate these rigs is a concern.

Source of historical data: <u>Reed Rig Census,</u> 1997–1998, and estimates from EEA, Inc.

Figure 11. Offshore Drilling Rig Fleet



- 72 additional offshore rigs will be needed.
- Additions may be from reactivations, new construction, or relocations.
- Availability of skilled workers is also a concern.

Source of historical data: Offshore Data Services, Rig Locator, September 24,1999 processes often negate those improvements. For example, increases in time required to perform studies previously conducted by government agencies, and obtain multi-agency permits have resulted in production project delays of up to two years on federal lands in the Rocky Mountain region. While the MMS has improved the approval process for offshore development by serving as the facilitator for the process, production and pipeline projects on land still require extensive interactions with multiple levels and agencies of federal, state and local governments. For example, the recently constructed Portland Natural Gas Transmission System involved the acquisition of over 150 permits and/or approvals from federal, state, and municipal government agencies. Most of the agencies involved in these processes have different data requirements, forms, and processes. Additional improvements are needed immediately in order to impact the development in the outer years of this study.

Changing Customer Needs

The ongoing regulatory restructuring of the natural gas and electricity markets changes the roles and responsibilities of all industry participants. As restructuring continues to unfold at the state level, the roles and obligations of LDCs and electric utilities will be changing. Other energy market participants may accept some aspects of the former roles of the LDCs and electric utilities as services are unbundled. These other participants, such as producers, generators, marketers, energy service providers, and end-users will contract for and use capacity differently than the LDCs and traditional electric utilities. In addition, new flexible services will be required to meet the anticipated increase in gas demand for electricity generation as projected in this study. For example, natural gas-fueled turbines (simple and combined cycle) have unique operating requirements in terms of inlet pressures and operations. Since electricity cannot be stored, the electricity generation systems must be constantly monitored and adjusted to change output instantaneously as electricity demand changes. Thus corresponding changes in natural gas demand occur constantly throughout the day. These changes in roles, services, and customer requirements will cause all sectors of both the natural gas and electricity industries to manage their assets differently.

SENSITIVITY ANALYSES

As discussed earlier in this report, sensitivity analyses provided some important information regarding the importance of the critical factors (see Figure 12a). Demand, for example, can increase by 0.6 TCF in 2010 if gross domestic product (GDP) grows by 3.0% annually instead of 2.5%. Conversely, GDP growth of 2.0% could result in a decrease in demand of 0.9 TCF by 2010. If crude oil price averaged $22.00 rather than $18.50 as assumed in the Reference Case, demand could increase by 0.7 TCF in 2010. However, demand would be 1.0 TCF lower if crude oil price averaged $15.00.

The model's output on price also served as a gauge for quantifying the impact of certain assumptions (Figures 12b and 13). While the model projects an average production weighted U.S. wellhead gas price through 2010 of approximately $2.74 per million British thermal units (MMBtu), prices in the sensitivity analyses change significantly. For example, the model projects that gas prices could be as much as $0.32 per MMBtu lower in 2010 if technology improvements are significantly better than assumed in the Reference Case. Conversely, a slower pace of technology improvements could drive the price up by $0.27 per MMBtu.

The single most significant assumption in the Reference Case is the size of the resource base. The model projects that the price of gas could be lowered by as much as $0.96 per MMBtu in 2010 if the economically recoverable resource base were found to be 250 TCF larger than assumed in the Reference Case. In this case, demand increases by 1.9 TCF and U.S. production increases by 1.5 TCF. A second sensitivity was run to examine the impact of a smaller resource base, although it should be noted that the resource base estimates have always increased over time. If estimates of the resource base are lowered by 250 TCF, prices could be as much as $0.56 per MMBtu higher, demand would be 1.5 TCF lower, and U.S. production would be 1.6 TCF lower. While this sensitivity was run to evaluate the impact of learning more about the resource base, it also provides some insight to the impact of access restrictions. Access is an important factor because it removes potential supply from the available resource base.

Figure 12a. Influence of Key Assumptions on Natural Gas Demand

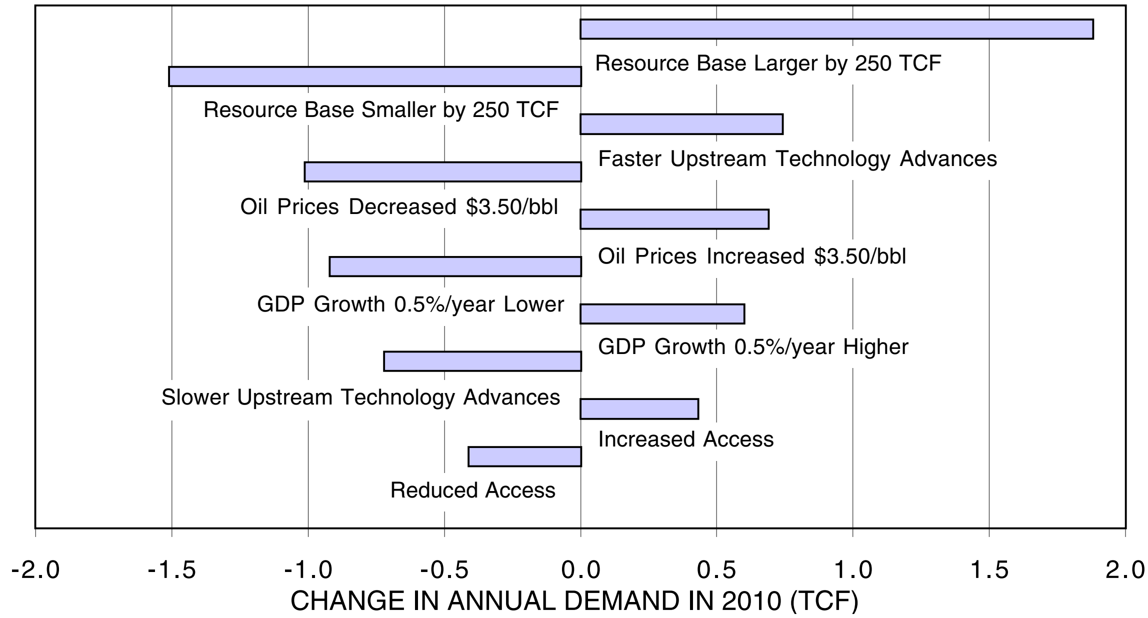
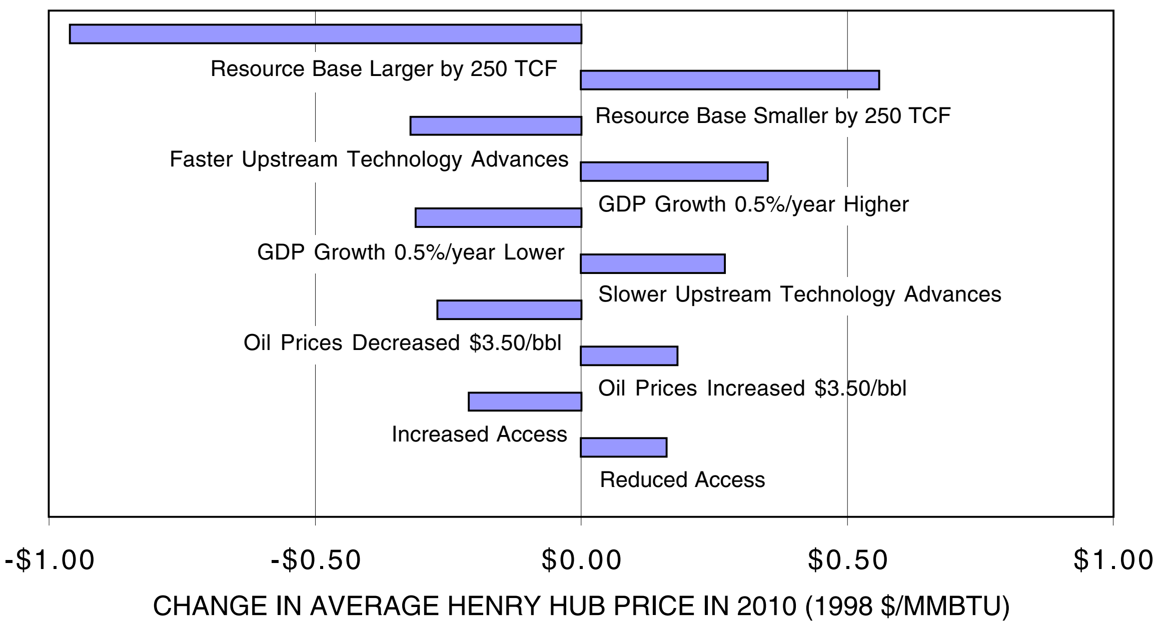


Figure 12b. Influence of Key Assumptions on Natural Gas Price

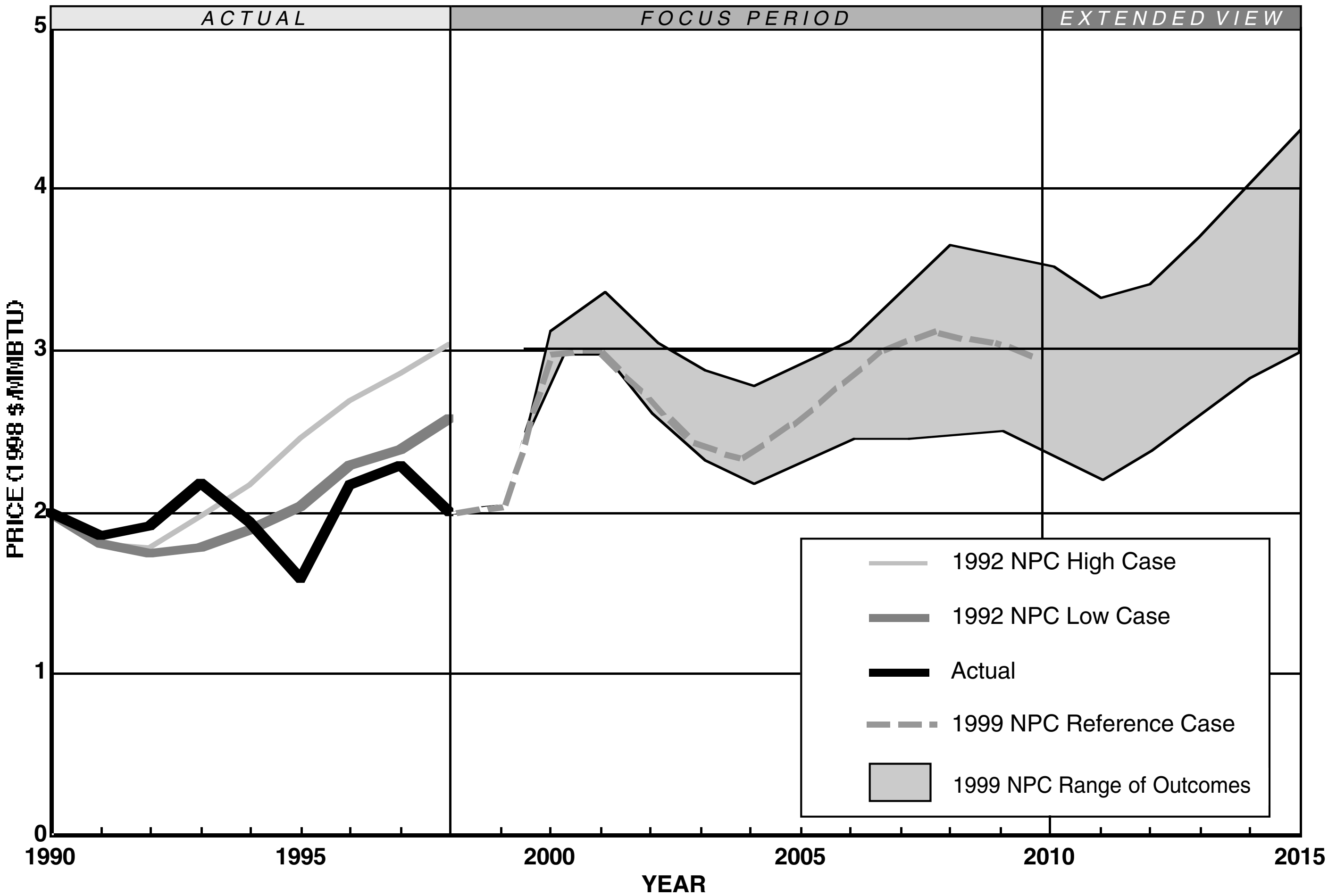


- A 15-20% change in the resource base has substantial impact on projected price and demand.
- Pace of technological advancement also has significant influence on projected price and demand.

NOTE: See Figures 14a and 14b for more details on resource base and access cases.

Figure 13. Historical and Projected U.S. Natural Gas Prices*

Lower-48 Weighted Average Wellhead Price



Prices are NOT intended to be a forecast. Seasonal factors such as abnormal weather and demand fluctuation have not been taken into account.

- Actual price for 1991–1998 averaged $1.97 versus 1992 study projections of $2.06–2.34.
- Price volatility will likely continue.
- Sensitivity analyses demonstrate the range of outcomes for key assumptions.
- The market will ultimately determine the price of natural gas.

Source: DOE/EIA, Monthly Energy Review, September 1999

Access restrictions also limit the opportunity to better assess the resource size in those areas.

To better quantify the impact of access restrictions, two additional sensitivity cases were developed. The first case tightened access restrictions in the Rocky Mountain region and eliminated the planned Lease Sale 181. In this reduced access case, price increased $0.16 per MMBtu in 2010 and demand decreased by 0.4 TCF. U.S. production decreased by 0.5 TCF. The second sensitivity case relaxed access restrictions in the Rockies and made currently restricted offshore regions available for leasing in 2004. This increased access case resulted in an increase in U.S. production of 0.5 TCF in 2010, an increase in demand of 0.4 TCF and a corresponding decrease in price of $0.21 per MMBtu. More importantly, a dramatic shift occurred in the Extended View period of the increased access case with an increase in demand of 1.5 TCF in 2015, a corresponding increase in U.S. production of 1.6 TCF (primarily from the Rockies and the eastern Gulf of Mexico), and a corresponding decrease in price of $0.45 per MMBtu (Figures 14a and 14b).

The most important conclusion derived from these sensitivity analyses is that the future availability and cost of natural gas can be influenced. While some variables cannot be controlled, factors such as the rate of technology development, knowledge of the resource base, and access to the resource base can be impacted—either positively or negatively—by the actions of the industry and the government.

The Council wishes to emphasize that the price output of the model is not to be used as a forecast, but rather as an indicator of the relative influence of the critical factors and assumptions. Seasonal factors that affect price, such as abnormal weather and demand fluctuations, have not been taken into account. The market will ultimately determine the price of natural gas. However, actions can be taken by industry and government to ensure that adequate supply is available, that it can be delivered to the market, and that the ultimate price is competitive through the study period and beyond.

Figure 14a. Impact of Size of Resource Base and Access on U.S. Natural Gas Production

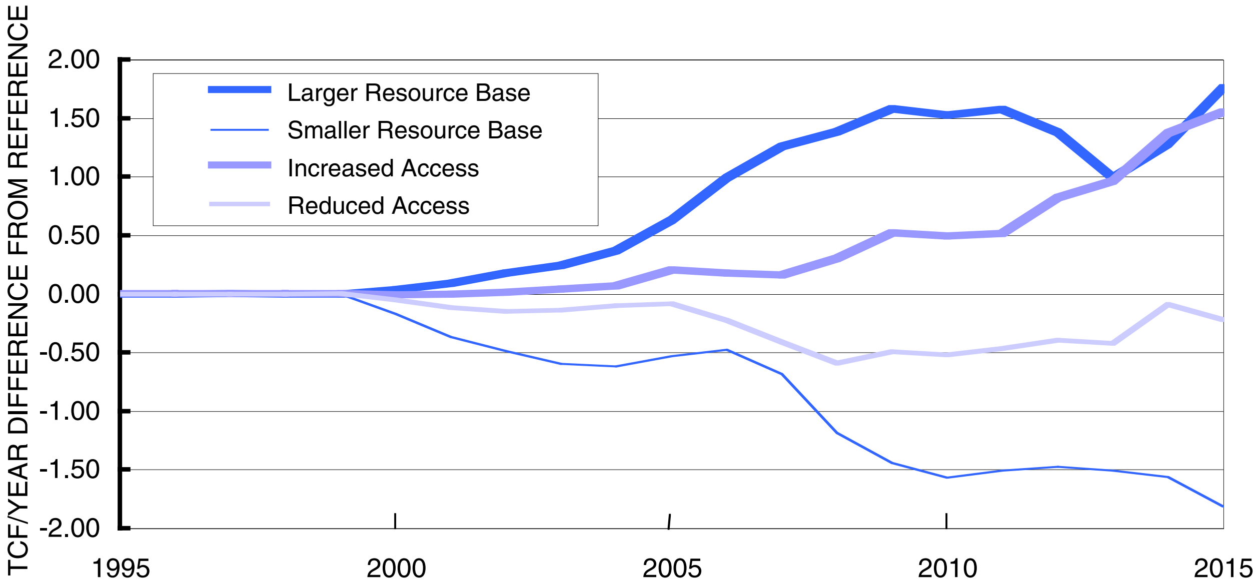
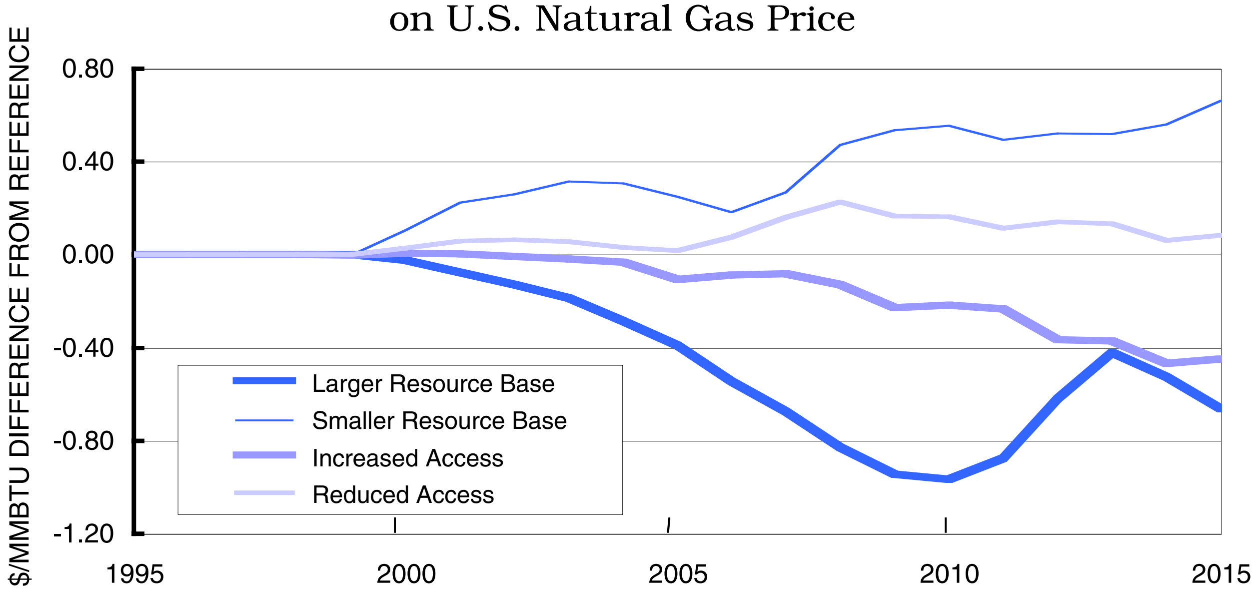


Figure 14b. Impact of Size of Resource Base and Access on U.S. Natural Gas Price



- Larger resource base would increase U.S. natural gas production 1.8 TCF in 2015 and decrease price $0.66.
- Smaller resource base would decrease U.S. natural gas production 1.8 TCF and increase price $0.66.
- Increased access would increase U.S. natural gas production 1.6 TCF in 2015 and decrease price $0.45.
- Reduced access would decrease U.S. natural gas production 0.2 TCF in 2015 and increase price $0.08.

In summary, affordable energy is necessary to sustain continued growth of the nation's economy and quality of life. Natural gas will play an important role, particularly as it helps the nation meet its environmental goals. By 2015, more than 14 million new customers will be connected to natural gas supply through over 300,000 miles of new transmission pipelines and distribution mains. Many more customers will use electricity that is fueled by natural gas as over 140 gigawatts of new electricity generation capacity—almost entirely gas-burning units—go into service. These new customers, as well as the existing customer base, are counting on long-term availability of reliable, competitively priced natural gas to meet their energy needs and to support the nation's environmental goals. Industry, government, and other stakeholders must act quickly, cooperatively, and purposefully to meet those expectations.

Recommendations

The Council wishes to emphasize that gas supply, and the associated infrastructure, can be expanded to meet growing demand if the critical factors are adequately addressed. The following recommendations are made by the Council to ensure that the mutual goals of government, industry, and consumers are met. While recommendations are made to the government for specific actions, the Council does not advocate regulations or legislation that artificially alter market signals. Instead, the Council encourages changes that remove impediments which hinder the development of supply and infrastructure to meet market needs.

Recommendation 1: Government and industry must take a leadership position in establishing—at the highest level—a strategy for natural gas in the nation's energy portfolio. An Interagency Work Group on Natural Gas should be established to work with industry and other stakeholders to formulate the strategy and resolve issues.

The government can help to overcome the barriers to meeting future natural gas demand by establishing a national strategy for natural gas. This strategy should include the areas of supply, demand, and transmission/distribution and should address the issues of access to the resource base, technology development, environmental regulation, education of the future workforce, and financial incentives. It should also affirm and describe the role of natural gas in balancing the national objectives of economic growth, environmental protection, and energy security. The strategy must provide a proper balance between conflicting environmental and land-use interests, yet reflect a sense of urgency about developing natural gas supply and the delivery infrastructure given the long lead times required.

The Council recommends that an Interagency Work Group on Natural Gas be established within the National Economic Council to formulate this comprehensive natural gas strategy and identify and aggressively resolve the issues associated with the development of natural gas supply and supporting delivery systems. This Interagency Work Group should be analogous to, but distinct from, the Interagency Working Group on Energy that has been set up under the National Economic Council to address oil industry issues. This new Work Group should oversee the implementation of government-related recommendations contained in this report. It should also monitor, on a biennial basis, trends for the assumptions used in this study and progress on the identified critical factors in order to anticipate changes in the supply/demand equation. All federal agencies that have a role in natural gas policy, technology, and resource assessments should be members. The Work Group should make every effort to include input from industry and other stakeholder groups, including states with natural gas production or potential for production, in its strategy-setting process. This solicitation of stakeholder views should be as interactive as possible.

The industry must also step up to the leadership challenge and work with government and other stakeholders to identify and understand their issues associated with developing supply and delivery systems and to seek practical solutions. Industry must work with customers to understand future supply and delivery needs and work with government to shape appropriate strategy and policies so that the required services can be provided in the most cost-effective manner while ensuring safety and reliability. Industry councils and trade associations can play an integral role in this effort.

Recommendation 2: Establish a balanced, long-term approach for responsibly developing the nation's natural gas resource base.

As seen in the analysis of critical factors in this report, the estimated size of the resource base is the single most important factor in projecting availability of competitively priced natural gas. While the ultimate size of the resource base cannot be changed and cannot be precisely known, industry can continue to improve its knowledge of the size and characteristics of the resource base, thus improving the likelihood of locating and producing new supply. However, access to a significant portion of this resource base for either assessment or development is subject to restrictions due to environmental and land-use concerns. These concerns are appropriate for consideration in granting access to potential supply areas, but significant improvements in the industry's environmental footprints warrant a new look at these restrictions.

Given the compelling need for developing economic natural gas supply, the following actions are recommended:

- *Government agencies and industry representatives should continue the work begun with this study to inventory existing information on the resource base in the Rocky Mountain region and analyze the impact of access restrictions.* A significant portion of work associated with this study included a first-time assessment of resource impacts associated with land access restrictions and related environmental stipulations in six areas in the Rockies. The results were then extrapolated to the entire region. This involved a cooperative effort between members of the Supply Task Group and representatives from the federal government, including the U.S. Department of Energy, the Bureau of Land Management, and the U.S. Forest Service. Representatives from state and local governments, as well as other stakeholders, also participated. This analysis, and the cooperative approach, should be continued and expanded beyond this study to increase understanding of the impact of access restrictions in the Rockies.

- *Industry should work with the government to prioritize restricted areas on the basis of resource potential as well as environmental sensitivity.* Certain restricted areas should be more fully assessed to determine the potential for gas supply. Those with higher potential and lower sensitivity should be opened for additional geological assessment. Industry should work with the government to identify methods and technologies that could be practically applied to minimize the environmental impact of the assessment.

- *A comprehensive approach should then be established for developing gas supply in selected restricted areas.* Existing moratoria should be reviewed and modified as appropriate. Industry should continue to develop practical techniques that minimize environmental impact, particularly for these sensitive areas. Once a long-term development plan is in place, the affected agencies should work together to coordinate their roles in assisting that development. A template for long-term planning and coordination among multiple agencies can be found in the MMS and their management of the offshore region.

- *Long-term sustainability of natural gas supply should be addressed.* The current study finds that, with focused effort, the gas demand through 2015 and well beyond can be met with sustainable gas supplies from U.S. and Canadian resources The life of the resource base can be further extended by encouraging efficiency at the burner tip. However, the Council also recognizes that at some point in the future—though probably not within the timeframe contemplated by this report—the United States will need to develop resources in what are now regarded as far frontiers. Such sources might include Alaska, large-scale LNG imports from a variety of foreign sources, and possibly gas transported by pipeline from the Caribbean and Latin America.

  Gas hydrates—frozen crystals of methane and water found both below the ocean floor and in Arctic regions—could also be a potential source of natural gas. In *Turning to the Sea: America's Ocean Future*, the Secretaries of

Commerce and Navy recommend the acceleration of scientific research on ocean hydrates. In addition, the Department of Energy's Office of Fossil Energy issued a document, *A Strategy for Methane Hydrates Research & Development* (August 1998), that provides for a comprehensive national research program that includes both marine and Arctic hydrate resources.

Projects to reach the far frontiers will be very expensive and will have extremely long lead times. At some point during the study period, government and industry must begin a cooperative, public planning process to lay the groundwork for far frontier projects.

The recommended Interagency Work Group could play a very important role in addressing access issues and the long-term sustainability of natural gas supply. The Work Group should be assigned the following responsibilities:

- Establish a set of principles that would guide federal land management policy. These principles should balance the national goals of economic growth, environmental protection, and energy security and should recognize the unique role of natural gas in meeting national objectives in the areas of clean air, climate change, electricity industry deregulation, and domestic energy supply. The guiding principles should also emphasize the need for multiple use of public land. Recognizing that it is the primary responsibility of the Secretaries of the Interior and Agriculture to establish land management policies within their jurisdictions, the guiding principles should help put those policies and priorities in a national policy context with respect to natural gas. The principles should be used by the appropriate land management and regulatory agencies to establish policies that promote domestic production of natural gas in order to meet national goals.

- Address the barriers that restrict access to natural gas resources in the Outer Continental Shelf and on onshore federal lands, particularly in the Rocky Mountain region where the majority of the onshore public gas resource is found. The goal of this effort should be to maximize the amount of economic natural gas resource available for development (consistent with effective environmental protection), reduce delays in natural gas exploration, production, and transportation, and improve consistency among federal and state agencies. The Work Group should oversee the continuing effort to inventory the impact of access restrictions on natural gas resources as discussed above. It should also evaluate the process by which access to the natural gas resource base and pipeline rights of way has been restricted in the past and may be further restricted in the future. The Work Group should look at the following categories of barriers:

— Land withdrawals that put natural gas resources off limits

— Regulatory and policy decisions that make natural gas resources effectively off limits or impractical to recover, such as:

  - "no surface occupancy" designations
  - use of stipulations more restricted than needed to protect environmental resources
  - old access restrictions that don't account for the effect of technology improvements that might allow development of natural gas in environmentally sensitive areas
  - air quality issues that threaten to delay or limit natural gas exploration and production.

— Decisions and applications of regulations and policies that increase the cost of or impose unnecessary delays in natural gas recovery and transportation, such as:

  - "combined hydrocarbon" leasing that imposes unnecessary costs on producers
  - cumbersome Coastal Zone Management process that impose delays on OCS leasing.

Recommendation 3: Drive research and technology development at a rapid rate.

Technology is another highly critical factor affecting both supply availability and price. Accelerating the development of technology is in the best interests of all stakeholders. The following industry and government actions are recommended:

- *Industry participants must aggressively build on past successes in advancing technologies by investing in research and supporting additional industry consortia.* Transmission and distribution companies should continue to invest in improving the efficiency of the delivery systems. All industry segments should explore additional applications that advanced information and communication technology can provide. Industry must continue to fund basic research, both independently and through grants to universities. Industry must also continue to invest in the development of technologies that reduce the environmental impact of exploration, production, and construction of infrastructure. Industry and consumers should continue to develop more efficient gas consumption equipment, thereby improving energy efficiency and yielding lower costs to consumers.

- *The government should continue investing in research and development through collaborations with industry, state organizations, national laboratories, and universities.* Efforts should be made to define key research and development priorities to support increased reserve growth in existing fields and new field discoveries in areas with the largest potential resource and to support expansion of the delivery infrastructure. Examples of specific research that government might sponsor include:

  — Reservoir detection and characterization technology targeted at exploration and field development

  — Technologies to reduce the cost of environmental compliance

  — Innovative geologic and engineering concepts based on novel technologies such as 3D and 4D seismic and horizontal drilling

— Technologies to further ensure the reliability, security, and integrity of the delivery system.

Particular consideration should be given to long-term technology needs for ultra-deep water, low permeability, and nonconventional reservoirs that will contribute more of the nation's gas supply in the future. Policy issues that affect technological developments should also be addressed.

- *The government should promote high-efficiency gas technologies such as fuel cells, gas cooling, and high-efficiency turbines.* Due to the inherent environmental advantages of natural gas and the high efficiencies offered by new gas equipment, the use of gas in place of other fossil energy forms promotes both energy conservation and environmental improvement (e.g., in areas such as acid rain, ozone formation, particulate emissions, and solid waste disposal). All energy efficiency evaluations and standards should be based on a "total energy efficiency" concept, that is, energy efficiency measurements should include energy used or lost from the point of production through consumption.

The recommended Interagency Work Group on Natural Gas can play a significant role in overseeing technology investments made by the government. Industry and state agencies should be actively involved with the Work Group in directing these efforts.

Recommendation 4: Plan for capital, infrastructure, and human resource needs.

The long-term demand growth projected in this study translates to long-term opportunities for the industry and the government. The increase in demand provides the opportunity for industry participants to expand their markets and to increase their service offerings. Benefits to the government extend beyond meeting environmental goals and include increases in revenues from royalties, rentals, and bonuses from the leasing of federal lands and development of the resources. For example, income generated by the Offshore Mineral Management Program alone generates about $4 billion annually.

However, taking full advantage of these opportunities will require long-term resource planning on the part of industry and government. The following areas should be specifically addressed:

- *Industry must immediately address concerns regarding the future availability of skilled workers.* Several years are required to train highly skilled workers to perform their jobs knowledgeably, efficiently, and safely. Given the projected increase in activity and the impending increase in retirements, aggressive action must be taken to attract, train, and retain qualified workers at all levels. Industry must also undertake initiatives to attract high school students with strong math and science skills to replenish college enrollments in petroleum, geotechnical, and other energy-related disciplines. Government funding of energy-related studies in universities can also help to populate these disciplines.

- *Producers, drilling companies, and equipment manufacturers should form a joint industry task force, headed by the International Association of Drilling Contractors, to gather additional information on infrastructure needs.* Of particular concern is the projected need to increase the number of wells drilled per year and increase the drilling rigs and equipment required to accomplish that task. The task force can begin its study by collecting data, such as drilling success rates in deeper formations and drilling rates for deep vertical wells, that are needed for assessing future needs. The task force should include rig builders and shipyard operators as well as industry groups such as the Petroleum Equipment Suppliers Association.

- *Government should examine possible new financial incentives, such as limited-duration tax and royalty incentives, that would accelerate the development of high-risk, high-cost natural gas resources onshore and offshore.* Past support from the government, such as tax credits and deepwater royalty relief, has promoted development activity. The MMS, in their January 1999 publication on deepwater development facts, states "The Deepwater Royalty Relief Act, passed in 1995, has contributed significantly to the increase in deepwater activity by providing the opportunity to lease new prospects in deepwater." The MMS reports that Gulf of Mexico OCS bids for leases in water greater than 800 meters increased from 49 in 1994 to 1,138 in 1997 and 817 in 1998. Other types of incentives should also be explored with input from industry advisors. These incentives, if properly targeted, can convert non-economic resources into economic supply.

Recommendation 5: Streamline processes that impact gas development.

Once a high level policy is established, all agencies involved in the development of supply and delivery systems should review and align existing policy to eliminate conflicting directives and remove obstructions. Processes that affect development must be streamlined to eliminate duplicative efforts, follow more predictable time-lines, and eliminate unnecessary costs to the industry, government, and, ultimately, consumers. Approval processes involving multiple levels of government, and agencies should be coordinated in order to resolve conflicts in a timely manner.

- The Council recommends that the following areas be evaluated:
- Updating of resource management plans for federal lands
- Potential for sharing land management and environmental assessment resources, such as data bases and personnel, among agencies
- Designation of sufficient budgets for required land-management planning and studies
- Adequacy of legislation for land-management policy and procedures
- Opportunities for coordinating permitting/approval processes among agencies.

Recommendation 6: Assess the impact of environmental regulation on natural gas supply and demand.

Additional evaluation is needed to fully assess the impact of existing and proposed environmental regulations on natural gas supply and demand. As shown in this study, regulations that address issues such as climate change and emissions controls on electricity generation could have a significant impact on natural gas demand and the ability of the industry to meet that demand. Changes in regulations and additional moratoria or extensions of existing moratoria that reduce access to natural gas supply should be examined in the context of the need for increasing gas supply. The recommended Interagency Work Group could play an important role in this analysis by developing and coordinating a process for reviewing any proposed regulations to ensure that the benefits of increasing natural gas use are considered in the regulatory process.

Recommendation 7: Design new services to meet changing customer needs.

In response to the ongoing restructuring of the natural gas and electricity markets, all industry participants must offer new or reconfigured services specifically designed to meet changing customer needs. For example, individual pipelines and many LDCs are implementing new services to meet customer needs through filings for services such as parking, loaning, balancing, peaking, and hourly firm transportation. While industry-wide changes may take some time to implement, individual pipeline changes can be developed and approved in far less time. When new services are offered to gas customers, maximum choice should be ensured by allowing all parties to compete for the provision of those services in a non-discriminatory manner.

The members of the National Petroleum Council stand ready to further discuss and implement the recommendations made in this report. Members will assist the Interagency Work Group in identifying impediments and solutions to the mutual goals of government, industry, and consumers for increased availability of competitively priced, environmentally desirable natural gas.

Summary of Key Findings

The following information supplements the conclusions and recommendations with an overview of the findings from the three task groups. Additional detail on the findings, assumptions, sensitivities, and model output can also be found in the task group reports.

The various projections and sensitivities presented in this report were prepared using market simulation models developed by Energy and Environmental Analysis, Inc. (EEA). The oil and gas supply projections were prepared using the GRI Hydrocarbon Supply Model, which was integrated with the gas demand, storage, and transportation elements of EEA's Gas Market Data and Forecasting System.

The GRI Hydrocarbon Supply Model was originally developed by EEA for GRI in the early 1980s and was the basis for the gas supply projections and scenario analysis for the 1992 NPC gas study. The model characterizes oil and gas exploration, development, and production in nineteen U.S. and five Canadian regions. Each region is further broken down into four to eight subareas, usually representing drilling depths for onshore regions or water depths for offshore regions. Proved reserves and undiscovered resources for gas are divided into associated-dissolved gas, conventional high permeability gas, tight gas, shales, and coalbed methane. The Hydrocarbon Supply Model provides the user with a wide range of options for selecting assumptions for resource base, drilling and development cost, technological improvements, upstream environmental compliance costs, land access, and financial parameters.

The Hydrocarbon Supply Model's projection of future natural gas deliverability by region was used in the Gas Market Data and Forecasting System to solve for monthly gas production, storage activity, pipeline flows, end-use consumption, and prices at locations in the United States, Canada, and the Mexico/U.S. border. This model was used to project gas demand in the United States and Canada and to determine the pipeline and storage infrastructure that would be economically justified in the various cases developed for this report. Key inputs to the model that can be varied among cases include a wide variety of drivers to gas demand and infrastructure-related parameters such as the cost of new pipeline and storage facilities.

Each task group established key assumptions and identified the variables that could significantly influence the model in their study area. Some of the key assumptions used in the current study for the 1999–2015 period are listed in Table 1.

Table 1
Key Model Assumptions

U.S. GDP Growth	2.5% per year
Canadian GDP Growth	2.2% per year
U.S. Industrial Production	3.0% per year
U.S. Inflation rate	2.5% per year
Crude oil price (WTI)	$18.50/bbl in 1999 dollars
Crude oil price (RACC*)	$16.50/bbl in 1999 dollars

* Refiners' Average Cost of Crude in the United States.

As indicated in Table 1, the model uses a U.S. GDP growth rate of 2.5% per year throughout the study period. This rate is below the rate at which GDP has grown in recent years. However, history has shown that recessions have interrupted periods of significant growth and resulted in a lower average growth over an extended period. The Council concluded that a 2.5% growth rate was reasonable, but sensitivity analyses were conducted to test the effects of both higher and lower rates. The Canadian GDP growth rate was assumed to be 2.2%, or 0.3% lower than the U.S. rate, reflecting a relative value that has prevailed over the last 10 years.

The crude oil prices used in the model were selected to approximate the average real prices experienced in the 70 years from 1929 to 1998. These crude oil prices affect the outcome of the model by determining the wellhead values of crude oil and natural gas, thereby setting the price of fuel oils that compete with natural gas in end-use markets. The oil prices also strongly influence the amount of capital that producers have available for reinvestment in exploration and production development. Sensitivity analyses were run to test the effect of both higher and lower oil prices.

FINDINGS OF THE DEMAND TASK GROUP

Demand Finding 1: Rapid growth exceeded expectations of the 1992 study.

Consumption of natural gas grew much faster in the 1990–98 period than was anticipated. Despite the warmer-than-normal weather that prevailed in 1998, demand grew over that nine-year period in all end-use categories. The various studies of natural gas demand that have been conducted in the past decade have consistently underestimated actual growth in demand. The 1992 NPC study was no exception, as shown in Figure 2. The High Reference Case in the 1992 study projected that total demand could grow from 19.3 TCF in 1990 to 24.8 TCF in 2010, with 1998 projected at 20.9 TCF. Actual demand in 1998 was 22 TCF (including net storage fill), or about 1 TCF ahead of the level forecast for 1998 in the 1992 study.

Several factors caused the 1992 study to underestimate actual growth in gas demand. Growth in GDP was assumed to be 2.4% annually and actual growth for the 1990–98 period was 2.6%. Although energy intensity measured by BTU/unit of growth declined between 1990 and 1998, it declined at a much slower rate than the 1992 study had anticipated. Most of the increased gas demand occurred because of an increase in total energy demand.

Gas demand grew during this period, even as the market was restructured significantly. In 1990, prior to the restructuring, over 90% of the gas moving in interstate pipelines was owned by the pipeline companies. FERC actions in the early 1990s have transformed interstate pipelines from sellers and transporters to solely open-access transporters. Many state regulatory agencies and LDCs are moving toward the same type of transformation.

In addition, major consolidations have occurred within the gas industry in anticipation of and response to the restructuring of the gas and electric industries. Numerous combinations of energy service providers have occurred within and across industry segments, as evidenced by the combinations of gas and electric companies. In most cases, mergers have been driven by the need to improve competitive position through economies of scale, greater geographic spread, more diversified services, and acquisition of expertise. These actions, along with increasing competition, have resulted in services that are generally more responsive to customer needs and are provided at lower prices.

The gas delivery system has remained the safest form of transport and continues to provide reliable service despite these massive changes. *Natural gas consumption has grown to a degree that its most ardent supporters would have found amazing at the time the 1992 NPC study was prepared.*

Demand Finding 2: Demand is projected to increase by 32% between 1998 and 2010.

U.S. natural gas consumption is projected to grow from 22 TCF in 1998 to 29 TCF in 2010 and could increase beyond 31 TCF in 2015 (see Table 2). Canadian gas demand is expected to rise from 2.8 TCF in 1998 to 3.5 TCF in 2010 and 3.8 TCF in 2015.

Table 2

U.S. Natural Gas Consumption (TCF)

	1998	2005	2010	2015
Total Consumption	22.0	26.3	29.0	31.3
Total End-Use	19.4	24.0	26.4	28.7
Residential	*4.5*	*5.6*	*5.8*	*6.1*
Commercial	*3.0*	*3.7*	*3.8*	*4.1*
*Industrial**	*8.6*	*9.6*	*10.2*	*10.8*
Electricity Generation	*3.3*	*5.1*	*6.6*	*7.8*
Lease, Plant, & Pipeline Fuel	2.0	2.2	2.5	2.5
Net Storage Fill/Balancing	0.6	0.1	0.1	0.0

*Historical data include all gas use for industrial cogeneration and independent power producers; all gas for new power plants except cogeneration is included in the electricity generation sector.

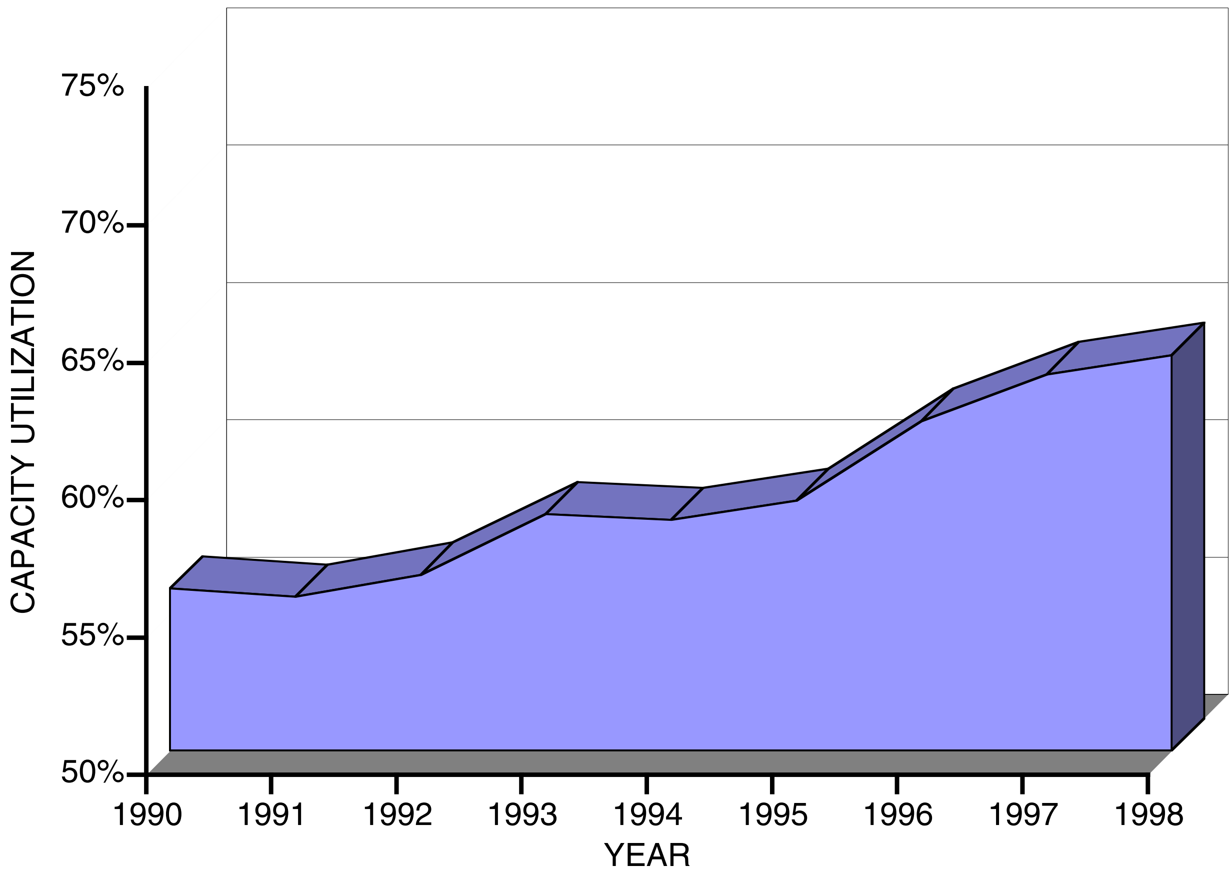
Source: Energy Information Administration, *Natural Gas Monthly*, September 1999.

The most significant growth in gas demand is projected to be for electricity generation. In the 1992 study, increased penetration of the electricity generation market was an *expectation*. Today—as a result of a dramatic improvements in heat rate for combined cycle gas/oil generating equipment, the relatively low capital cost of such plants, the relatively short construction time required to bring them on line, tighter emission standards for electricity generation, and the deregulation of the electricity industry—gas is the *preferred choice* of the electricity generation industry for new generating plants. Currently, 96% of the more than 200 fossil fuel generating plants that have recently been announced for construction in the next five years have specified gas; the remaining 4% will be coal- or wood-fired.[1]

[1] Source: Online data base at Resource Data International, Inc. (July 1999)

A number of key assumptions were made concerning electricity generation. One assumption was that 113 gigawatts of gas/oil combined cycle and gas-fired combustion turbine capacity would be operating by 2010 (an increase from 25 gigawatts in 1998) and a total of 140 gigawatts by 2015 to satisfy incremental electricity demand. The study determined that, through 2010, the cost of electricity generated from new coal plants (including capital costs) would not be competitive with electricity from new gas units, but that after 2010 an estimated 20 gigawatts of new coal capacity would be built. Heat rates for all classes of electricity generation are assumed to improve 3 percentage points between 1998 and 2015. Seventy percent of combined cycle plants are assumed to be capable of burning either gas or oil and would therefore switch fuels depending on cost. Coal capacity utilization was assumed to increase 11 percentage points from 64% in 1997 to 75% by 2015, continuing the trend observed in the last 10 years (Figure 15). However, this continuing increase in capacity utilization is recognized as a significant challenge for those facilities. Adding to this concern is the legal action taken in November 1999 by the EPA against several large utility companies, charging that their coal-fired plants had effectively added to their capacity during maintenance without installing new pollution control equipment. This recent action could have the impact of lowering coal capacity utilization, thus increasing demand for natural gas.

Figure 15. U.S. Central Utility Coal-Fired Electricity Generation Capacity Utilization

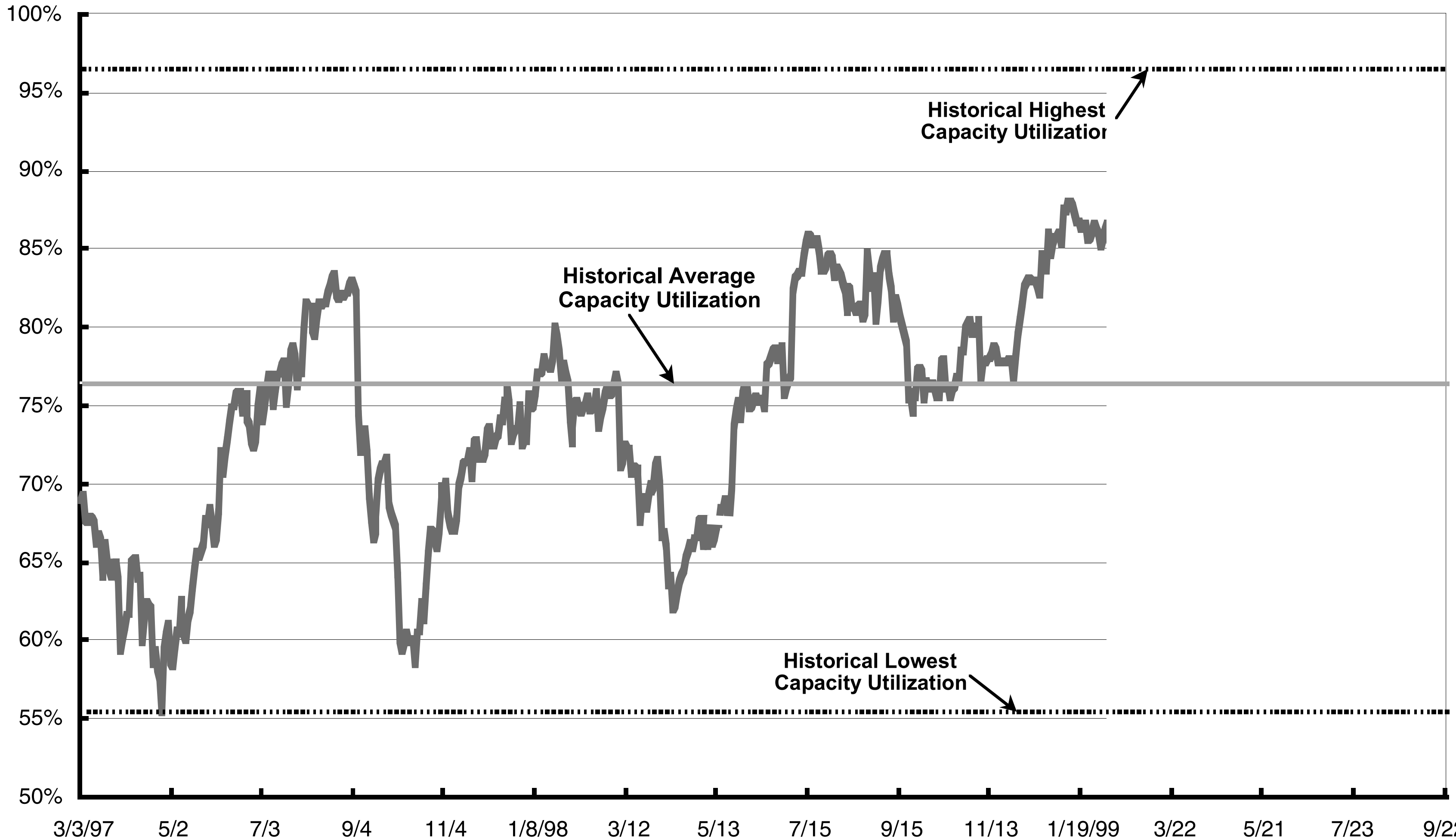


Source: DOE/EIA, Electric Power Annual, 1990–1998

No new nuclear capacity was projected to be developed in the timeframe of this study and an estimated 15 gigawatts of nuclear generation capacity is projected to retire by 2015 as some licenses expire. The Demand Task Group projected that 15 gigawatts of nuclear capacity would be relicensed, and that a total nuclear capacity of approximately 80 gigawatts would remain in operation in 2015. The electricity generation industry has increasingly relied on its nuclear generation capacity, as seen in Figure 16. With the resumption of service at the Clinton, LaSalle, and Millstone units in the spring of 1999, nuclear capacity utilization reached an unprecedented peak of 96.5% in August 1999. This compares to the previous peak capacity utilization of 86% in July 1998 and the historical average of approximately 75%. The average annual capacity utilization of nuclear generating capacity is assumed to increase from 75% to 80% over the study period. Nuclear retirements beyond the few projected in this study could significantly increase natural gas demand in the 2010–2015 time frame.

Hydroelectric and renewable generation are assumed to remain nearly constant throughout this case, although hydroelectric generation could diminish due to environmental concerns about the adverse impact of dams on anadromous fish populations, especially in the Pacific Northwest. However, such declines are assumed to be nearly offset by increased generation from renewable energy such as wind and solar. Increases in renewable capacity are evident because of existing and growing demand for "green power," and state-level legislation calling for renewable portfolio standards.

The Demand Task Group recognized that assumptions for key variables have a significant impact on ultimate demand. As discussed, assumptions were made for the Reference Case about the rate of increase in GDP, prices of competitive fuels (e.g., fuel oil and coal), construction of new gas-fired generating plants, the retirement of nuclear plants, and utilization rates of gas, coal, and nuclear plants. The highest-impact variables were tested with sensitivity analyses. GDP growth and oil prices proved to be significant drivers of gas demand. For



Source: U.S. nuclear complex activity data, BTU Daily example, if GDP growth were to average 3.0% per year rather than 2.5%, demand could increase by 0.6 TCF in 2010. An average GDP growth of 2.0% could result in 0.9 TCF lower demand in 2010. If oil prices were $3.50 higher than assumed in the Reference Case, demand could increase by 0.7 TCF. Conversely, if oil prices were $3.50 lower, demand could be 1.0 TCF lower than the Reference Case.

The assumptions regarding other fuels that are used for electricity generation can also have a large impact on demand. For example, if the capacity utilization factor of coal-fired plants is 65% rather than the 75% assumed in this study, gas demand could increase by 1.7 TCF. If an additional 15 gigawatts of nuclear retirements were to occur, demand could increase as much as 0.7 TCF. Further detail on these sensitivities is included in the Demand Task Group Report.

Demand Finding 3: Environmental regulations could add significant incremental demand.

The potential 29 TCF demand projected for 2010 does not include the effect of environmental and other regulations that are not currently scheduled for implementation. New legislation or policy initiatives that might be implemented to address global climate change could substantially increase gas demand. For example, the Energy Information Administration (EIA) and the Edison Electric Institute (EEI) have conducted separate studies of the impact of meeting the U.S. target under the Kyoto protocol. These studies, which are discussed in the Demand Task Group Report, confirm that substantial reductions in coal and oil consumption would be required with a concomitant increase in gas demand. These studies examine various scenarios and indicate an increase in gas demand of 2–12% in the case of EIA, and 10–22% in the case of EEI above their respective reference cases.

While this NPC study did not specifically analyze the effect of new environmental regulation, correlations can be made with other factors that affect demand and price. For example, the sensitivity analysis that examined a decrease in the utilization rate of coal-fired electricity generation capacity—which could easily occur with new environmental regulation—indicated that a significant corresponding increase in demand would occur.

FINDINGS OF THE SUPPLY TASK GROUP

Supply Finding 1: Sufficient resources exist to meet growing demand well into the 21st century.

The estimated resource base of 1,466 TCF for the lower-48 states in the current study represents a 171 TCF increase from the 1,295 TCF used in the 1992 study (see Figure 4 and Table 3). In addition, Canada's resource base is estimated at 667 TCF. Canada's resource base is approximately 73 TCF lower than determined in the 1992 study due to depletion and reassessment of nonconventional resources.

The Supply Task Group's team of industry experts on resource assessment conveys a high level of confidence in the robustness of the U.S. resource base. This team notes that the 171 TCF increase in the resource base has occurred despite production in the lower-48 states of 124 TCF of reserves from 1991 through 1997. The increase in the estimated resource base is primarily derived from technology improvements. For example, advances in computer technology have yielded breakthroughs in data processing, integration, and imaging, which have in turn vastly improved reservoir modeling. This information enables better projections of the size and location of hydrocarbon deposits. Technology has also played a significant role in improving drilling and completion

Table 3

U.S. and Canadian Natural Gas Resources
(Trillion Cubic Feet)

	1992 NPC Study (1-1-91)	**1999 NPC Study (1-1-98)**
Lower-48 Resources		
Proved Reserves	160	157
Old Fields (Reserve Appreciation)	*236*	*305*
New Fields	*493*	*633*
Nonconventional	*406*	*371*
Assessed Additional Resources	1,135	1,309
Total Remaining Resources (Proved + Assessed Additional)	**1,295**	**1,466**
Cumulative Production	758	881
Total All-Time Recovery	2,053	2,347
Alaskan Resources		
Proved Reserves	9	10
*Old Fields (Reserve Appreciation)**	*30*	*32*
New Fields	*84*	*214*
Nonconventional	*57*	*57*
Assessed Additional Resources	171	303
Total Remaining Resources (Proved + Assessed Additional)	**180**	**313**
Cumulative Production	5	9
Total All-Time Recovery	185	322
Canadian Resources		
Proved Reserves	72	64
Old Fields (Reserve Appreciation)	*24*	*22*
Discovered Undeveloped	*47*	*35*
New Fields	*379*	*384*
Nonconventional	*218*	*162*
Assessed Additional Resources	668	603
Total Remaining Resources (Proved + Assessed Additional)	**740**	**667**
Cumulative Production	65	103
Total All-Time Recovery	805	770

* Includes 25 TCF for Prudhoe Bay.

techniques, thus improving access to the resource base. The major contributors to increases in the resource base are:

- **Old Field reserve appreciation.** The application of new technology has helped in the assessment of hydrocarbons in known fields. The new information has resulted in an increase of 69 TCF in the estimates of the resource base in "Old Fields."

- **New Fields primarily in the deepwater Gulf of Mexico.** New information and improved interpretations have also yielded increases in projections for New Fields—fields that are theoretically in place but are yet to be discovered. For example, estimates of New Fields resources in deepwater Gulf of Mexico have increased to 140 TCF, a 145% increase from the 57 TCF estimate in the 1992 study.

Figures 17a and 17b show the U.S. and Canadian assessment regions and the "Assessed Additional Resources" for each region, which is the sum of Old Field growth, New Field discoveries, and nonconventional gas sources. Two areas, the Rocky Mountain Foreland and the Central and Western Gulf of Mexico, contribute almost half of the U.S. total. In Canada, the Western Sedimentary Basin (model region ASM) will provide a significant amount of the additional resource.

U.S. gas production is projected to increase from 19 TCF in 1998 to 25 TCF in 2010 and could approach 27 TCF in 2015. Canadian imports to the United States are projected to increase from 3 TCF in 1998 to 3.8 TCF in 2010 and could reach 4.4 TCF by 2015 (Table 4). Approximately 13–14% of U.S. gas supply will continue to come from Canada. LNG imports will reach 0.9 TCF using an average of 75% of existing U.S. capacity. No additional import facilities are projected in this study. Exports to Mexico are projected to increase in the near term to 0.4 TCF and remain at that level throughout the study period.

Figure 17a. U.S. and Canadian Assessment Regions

* Alaskan resources were not assessed in this study.

Figure 17b. Assessed Additional Resources by Region.

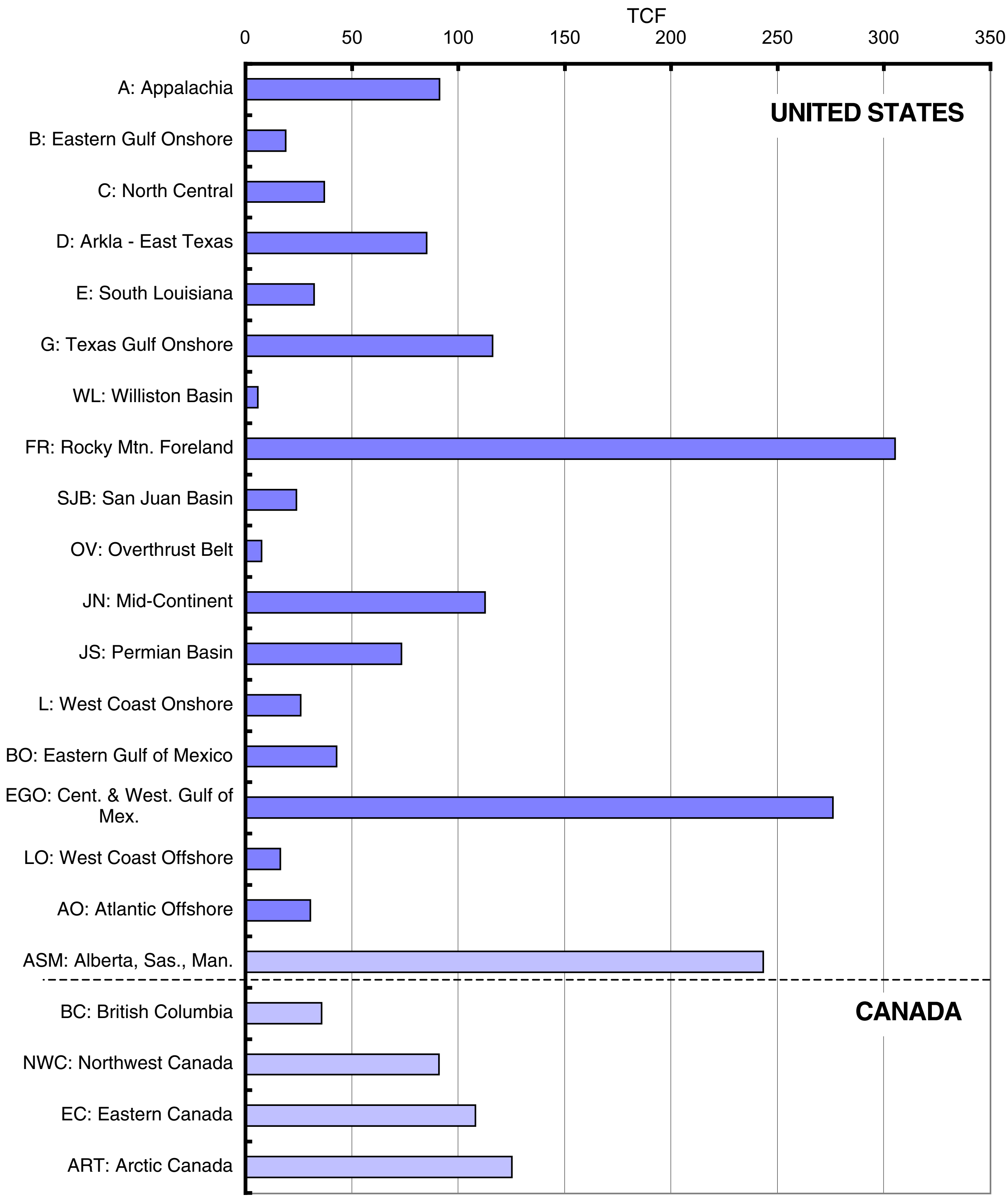


Table 4

U.S. Gas Supply
(Trillion Cubic Feet)

	1998*	**2005**	**2010**	**2015**
U.S. Gas Production	19.0	22.6	25.1	26.6
Net Imports from Canada	3.0	3.7	3.8	4.3
LNG Imports	0.1	0.4	0.6	0.9
Exports to Mexico and Japan	-0.1	-0.4	-0.5	-0.5
Total Supply	**22.0**	**26.3**	**29.0**	**31.3**
Canada as a % of Total	14%	14%	13%	13%

*Including synthetic natural gas.

Source: Actuals from Energy Information Administration, *Natural Gas Monthly* (September 1999).

Future production will be from deeper wells, deeper water, and more nonconventional sources. As Table 5 demonstrates, lower-48 production will gradually increase from deeper wells. Onshore production from depths below 10,000 feet is projected to increase from 33% in recent years to over 40% by 2010. The industry's ability to achieve production from deeper horizons will be dependent on the appropriate amount of deep drilling infrastructure and the continued evolution of technology.

Table 5

Onshore Lower-48 Gas Production by Depth Interval

	1998	**2005**	**2010**	**2015**
0–5,000 ft	28%	27%	25%	25%
5–10,000 ft	39%	37%	34%	32%
10–15,000 ft	26%	26%	29%	32%
> 15,000 ft	7%	10%	12%	11%

In the Gulf of Mexico, production from deeper waters will be the driving force in future supply growth, as demonstrated in Table 6. Production from water depths of more than 200 meters is projected to increase from 0.8 TCF in 1998 to over 4.5 TCF in 2010 and maintain approximately that level through 2015. Conversely, Gulf of Mexico shelf production is projected to decrease from 4.5 TCF in 1998 to 3.5 TCF in 2010 and around 3.0 TCF in 2015.

Growth in production from nonconventional sources will be especially pronounced in the Rocky Mountain region. Nonconventional production in this region is projected to increase from 1.9 TCF in 1998 to 2.9 TCF in 2010 and as much as 3.4 TCF in 2015. Production in the lower-48 states from nonconventional sources (i.e., the sum of tight gas, shales, and coalbed methane) accounted for 4.4 TCF of total production in 1998. This volume is projected to increase to 6.8 TCF in 2010 and could reach 8.5 TCF in 2015 (Table 7).

All of these new sources of gas require that significant technology hurdles be addressed and overcome in order to deliver cost-competitive supply. Two sensitivity cases were developed to determine the impact on price and demand if technology develops at either a slower rate or a faster rate. When technology improvements developed more slowly than in the Reference Case, demand in 2010 fell by 0.7 TCF and price increased by $0.27 per MMBtu. Conversely, when the rate of technology improvements increased, demand increased by 0.7 TCF, and price decreased $0.32 per MMBtu.

Sensitivity analyses were also run on the size of the resource base to evaluate the impact of learning more about the resource base. An increase of 250 TCF in the economically recoverable resource base, beyond the 1,466 TCF Reference Case estimate, resulted in a decrease in gas price of $0.96 per MMBtu. Conversely decreasing the estimate of the resource base by 250 TCF from the 1,466 TCF estimate, increased the price by $0.56 per MMBtu. The sensitivity analyses indicated that the assumption on the size of the estimated resource base has the highest impact on the ability to produce competitively priced natural gas.

Table 6

Gulf of Mexico Production by Water Depth

	1998*	2005	2010	2015
Gulf of Mexico Production (TCF/Year)	5.3	7.4	8.0	7.6
Conventional Production (%)				
Shelf 0–40 meters	49%	27%	20%	19%
Shelf 40–200 meters	35%	24%	20%	17%
Slope 200–1,000 meters	14%	26%	25%	23%
Slope 1,000–1,500 meters	0%	9%	13%	14%
Slope >1,500 meters	1%	8%	15%	18%
Subsalt Production (%)				
Shelf 40–200 meters	< 1%	3%	4%	4%
Slope 200–1,000 meters	1%	2%	2%	3%
Slope >1,000 meters	0%	1%	1%	2%

* Energy and Environmental Analysis, Inc., estimates adapted from Dwights/PI production reports.

Table 7

Lower-48 Production from Conventional vs. Nonconventional Sources (Percentages)

	1998*	2005	2010	2015
Associated Gas	14%	13%	14%	13%
High Permeability Gas	60%	62%	59%	54%
Tight Gas & Shale Gas	20%	20%	21%	25%
Coalbed Methane	6%	5%	6%	8%

* Energy and Environmental Analysis, Inc., estimates adapted from Dwights/PI production reports.

This sensitivity analysis provides some insight into the impact of access issues since access restrictions remove potential supply from the available resource base.

Supply Finding 2: Restricted access limits the availability of supply.

Access issues limit the ability to reach known resources, slow down development in certain areas, and impede the construction of needed pipelines required to deliver natural gas to markets. For the purposes of the current study, the following assumptions were made with regard to access: (1) all scheduled lease sales (including eastern Gulf of Mexico Lease Sale 181) will continue on time; (2) all existing regulatory requirements and restrictions on—and all current availability for drilling of—public lands are honored; and (3) rights of way will be obtained for constructing and expanding any necessary pipeline infrastructure. If any of these assumptions fall short, the ability to explore for, produce, and deliver adequate supply will be hampered. Enabling access beyond that assumed in the Reference Case is necessary to improve availability and cost-competitiveness of gas supply in the time period of this study.

Two areas that will significantly contribute to future gas supply are the Rocky Mountain region and the Gulf of Mexico, both of which have significant access restrictions. For example, approximately 9% of resource-bearing lands in the Rockies are completely inaccessible due to “no leasing” and “no surface occupancy” restrictions. Another 32% of resource-bearing lands are specifically subject to restrictions that delay development activity by an average of two years and add measurably to the cost of drilling wells on these properties. These restrictions mean that over 137 TCF of resources are subject to prohibitions or impediments. Another 76 TCF of resources are estimated for restricted offshore areas in the eastern Gulf of Mexico, the Atlantic, and the Pacific. Regardless of the lack of specific stipulations, nearly all public-lands acreage otherwise accessible for development regularly becomes encumbered to some degree in disputes among stakeholder groups and inconsistent application of regulatory policy by the governmental group(s) charged with managing these lands. These issues result in similar delays and added costs for offshore areas.

The current study assumes access to those tracts in planned Lease Sale 181, but not the resources in the eastern Gulf of Mexico beyond the Norphlet trend areas off Mississippi and Alabama. These areas have not been opened up and no plans to do so are currently in progress. Similarly, the Destin Dome area off the Panhandle of Florida was not assumed to be available for development in the Reference Case because the regulatory approval process was taking place during the time of this study.

Two sensitivity cases were developed to evaluate the impact of access on natural gas production. As seen in Table 8, the reduced access case assumed that further restrictions in the Rocky Mountain region would increase development costs and reduce the area that can be leased under standard terms. This case also assumed that the scheduled Lease Sale 181 would not occur. The reduced access case resulted in a price increase of $0.16 per MMBtu in 2010 and a decrease in U.S. production of 0.5 TCF. The declines in production occurred primarily in the Rockies and the eastern Gulf of Mexico. The decrease in production in 2015 was 0.2 TCF, with a decrease in price of $0.08 per MMBtu. The changes that occurred in the reduced access sensitivity case were not pronounced, primarily because the access assumptions in the Reference Case were already very restrictive.

The second sensitivity case assumed that access restrictions would be relaxed in the Rockies, resulting in the elimination of high-cost delays. Currently restricted offshore areas were assumed to be open to leasing in 2004 and production from the area opened in Lease Sale 181 would begin in 2002. This increased access case resulted in an increase in U.S. production of 0.5 TCF in 2010, 95% of which was in the Rockies and the eastern Gulf of Mexico. A corresponding decrease in price of $0.21 per MMBtu accompanied this production increase. More importantly, a dramatic shift occurred in the Extended View period with

Table 8

Summary of NPC Federal Lands and Waters Access Sensitivities

	Reference Case	**Increased Access Case**	**Reduced Access Case**
Rocky Mountains			
Standard Lease Terms	59%	59%	22%
Off Limits	9%	9%	14%
High Cost*	32%	32%	64%
*High Cost Penalty per Well	6% of Well Costs	0%	6% of Well Costs
*High Cost Delay	2 Years	None	2 Years
Eastern Gulf of Mexico			
Destin Dome	No Development	Production by 2002	No Development
Sale 181	Lease Sale in 2001	Lease Sale in 2001	No Sale
Non-Sale 181 Eastern Gulf	No Sale or Development	Lease Sale in 2004	No Sale or Development
Other Offshore U.S.			
Pacific	No Development	Lease Sale in 2004	No Development
Atlantic	No Development	Lease Sale in 2004	No Development

an increase in U.S. production in 2015 of 1.6 TCF. This increase continued to be primarily from the Rockies and the Eastern Gulf of Mexico, with some Atlantic offshore production beginning in this time frame. Prices in 2015 decreased by $0.45 per MMBtu.

Supply Finding 3: A healthy oil and gas industry is critical for natural gas supply to satisfy expected increases in demand.

Adequate financial performance must be demonstrated to compete for and attract financial investment.

The growth in gas demand projected in this study will require approximately $658 billion [constant 1998 dollars] in upstream capital expenditures from 1999 through 2015. This figure includes all exploration, development, production, and gathering capital expenditures. A summary of the capital investment requirements projected by the Reference Case in the 1999 to 2015 study period is shown in Figure 9.

This supply growth will require an increased annual average capital expenditure of $39 billion per year from 1999 through 2015, versus an annual average of $27 billion from 1991 through 1998. However, these needed levels of investment will take place only if investors have confidence that competitive rates of return will be earned. In recent years, this has not been the case as the U.S. upstream sector has earned very modest rates of return. According to the Financial Reporting System, the 23 largest producers reported an average return on assets of just 5.4% over the 12-year period from 1986 through 1997.

The assumption for future oil prices in the current study does not take into account the price volatility that has been experienced and that has caused difficulty in maintaining steady levels of upstream investments. The strong direct correlation between commodity prices and upstream investment means that investments drop rapidly following a significant downturn in oil or gas prices and confidence returns slowly. The historical low rates of return and the degree of volatility jeopardize the steady flow of capital that is needed to achieve the large projected increases in gas production required to meet growing demand.

Aggressive pro-active workforce planning is essential.

Without immediate action, impending shortages of qualified personnel are expected to hinder the ability of the supply sector to find and develop the required gas supply. Three major shocks to employment prospects in the producing sector have occurred in the last 20 years. Each of these shocks (1982, 1986, and 1998) was caused by drastic declines in the world market price of crude oil and resulted in significant reductions in expenditures and jobs. At the same time, companies dramatically decreased hiring rates. As a result, the producing sector now suffers from a very slim "bench" of mid-career workers between the ages of 30 and 40 and is facing a large wave of retirements.

In the aftermath of precipitous declines in crude oil prices in 1981, enrollments in key disciplines that support the producing sector began to decline drastically and gained momentum with the equally devastating oil price drop in 1986. The "farm clubs"—college and university petroleum-related degree programs—continue to have great difficulty attracting promising high school seniors. Enrollments in undergraduate petroleum engineering and geoscience programs have declined by 77% and 60%, respectively, between 1985 and 1998 (see Figure 18).[2]

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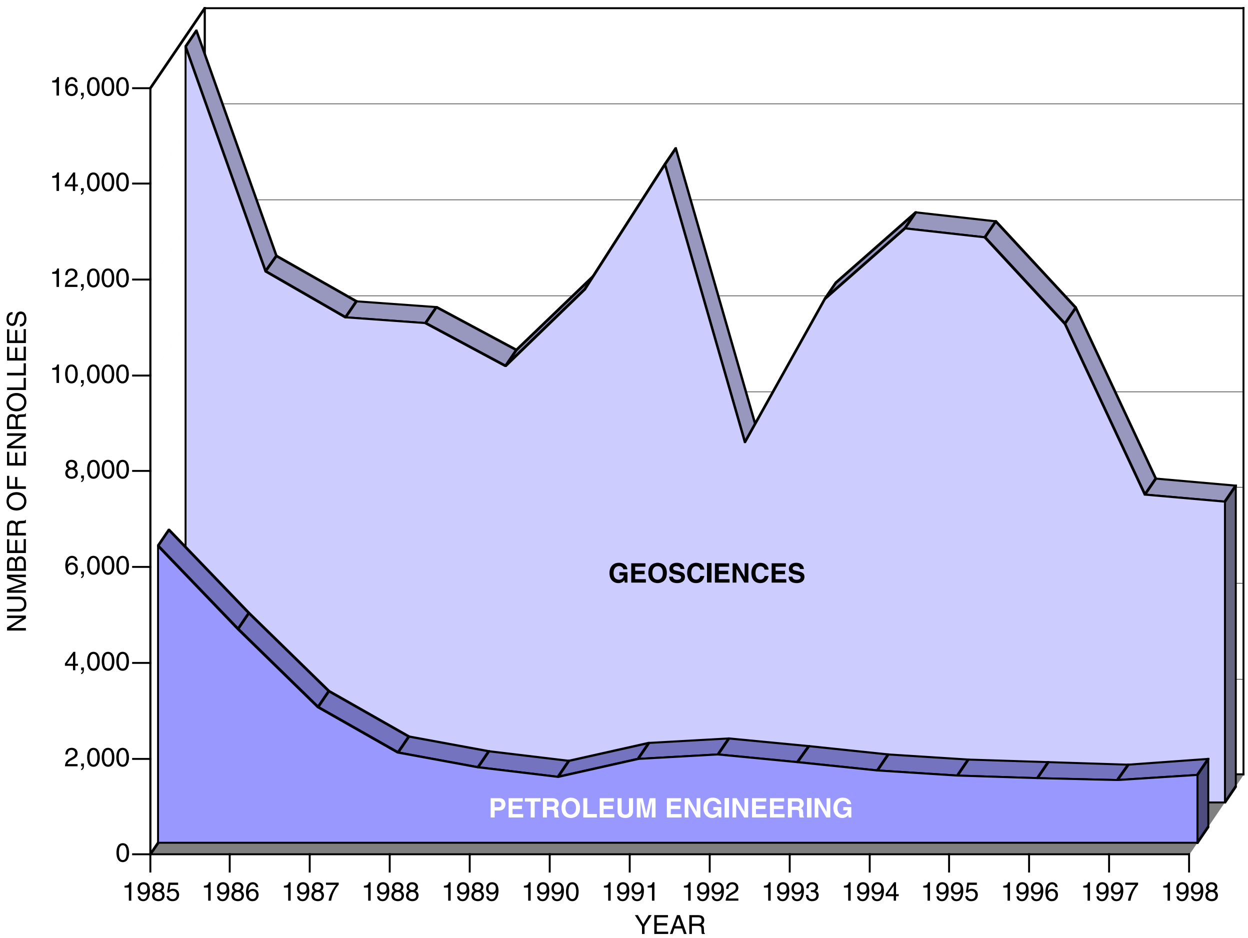
[2] Data from (1) *Petroleum Engineering and Technology Schools 1997-1998*, Society of Petroleum Engineers http://www.pe.ttu.edu/spe_schools_book/html/school.html , (2) *State of Oil and Natural Gas Industry*, Independent Petroleum Association of America, August 4, 1999.

Figure 18. Geoscience Undergraduate and Petroleum Engineering Enrollees



Source: Society of Petroleum Engineers, Petroleum Engineering and Technology Schools 1997-1998, and American Geological Institute

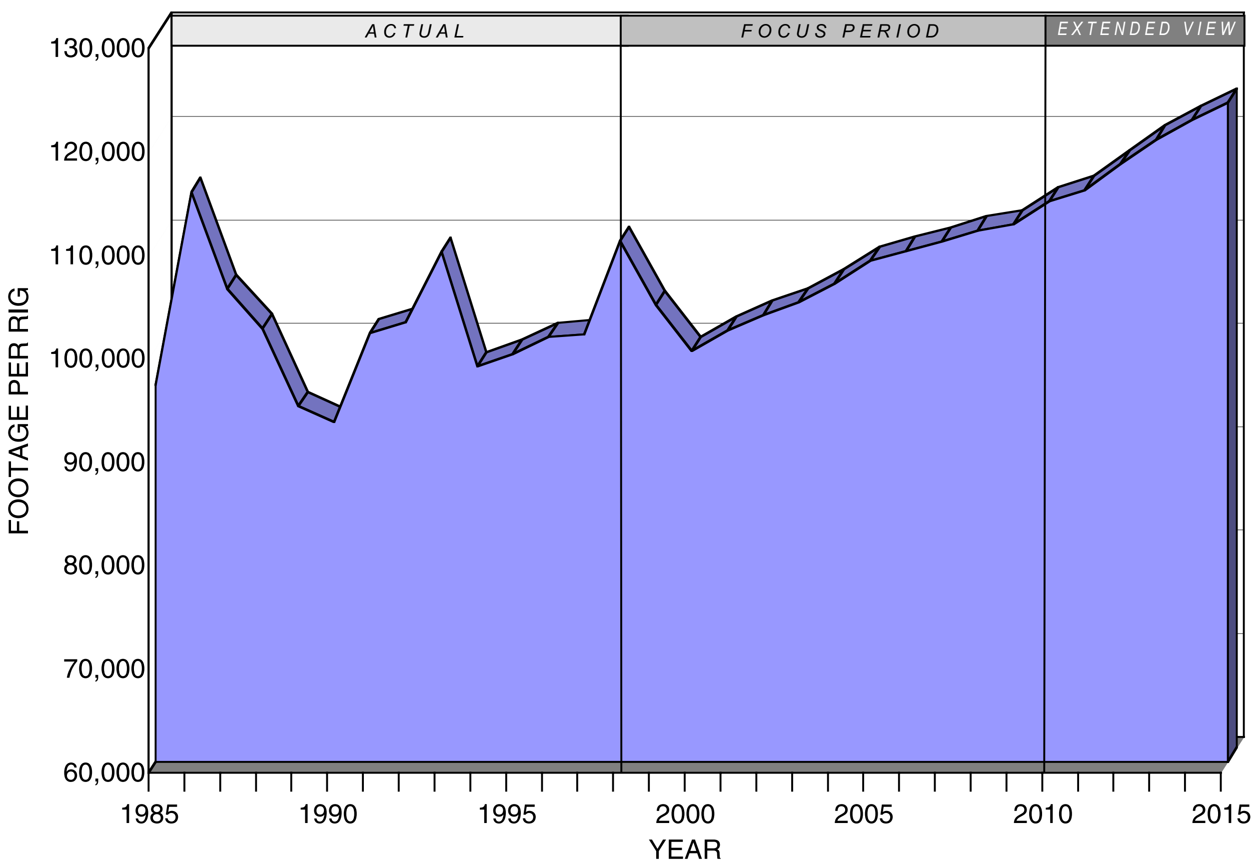
The oilfield service/supply sector faces similar challenges in meeting engineering and operations requirements. Volatility in the drilling industry has caused many toolpushers and other key supervisory personnel to leave the industry in search of more stable careers. Industry contractors will be challenged to find and train adequate numbers of skilled laborers, such as machinists, electricians, pipefitters, and welders. Higher wage scales are likely to be required to attract workers back into the industry.

Beginning immediately, aggressive pro-active workforce planning is a necessity for producers and contractors to achieve staffing levels that are necessary to meet the challenge of the projected demand increase.

New drilling rigs must be built.

In order to supply the volume of natural gas needed through this study period, the total number of wells drilled annually must increase from 24,000 in 1998 to 37,000 in 2010 and as high as 48,000 by 2015. The well counts include both gas and oil wells because approximately 14% of natural gas produced in the United States is associated gas. In 1998, an average of just over 1,250 onshore rigs of the 1,700 rigs available have been active. While rig efficiency (footage drilled per rig, see Figure 19) has improved since 1985 and is expected to continue to improve over time with technology advancements, increased well depth requirements will likely cause the current number of actual wells drilled each year per active rig to remain relatively constant. Thus, to drill 48,000 wells annually by 2015 an average of 2,100 onshore rigs and 180 offshore rigs will be required to actively drill each month of the year.

Figure 19. Annual Average Footage Drilled Per Rig



Source of historical data: API, Quarterly Completion Report ; and Baker Hughes, Inc., Rotary Rigs Running

With this increased level of drilling, the availability of drilling rigs becomes a primary concern. Over the 1999–2015 time frame, the number of onshore rigs that will be retired or lost to attrition is estimated at 90% of the current fleet. In order to meet estimated rig demand, over 1,125 onshore rigs would need to be constructed by 2010 and as many as 1,894 by 2015. Onshore rig construction will be needed as early as 2001. Capital requirements for onshore rig construction is projected at $12 billion.

Additional offshore drilling rigs will also be needed in this time frame, as shown in Table 9. As of September 24, 1999, the offshore fleet actively drilling in the Gulf of Mexico numbered 207, with 30 of those working in deepwater. Included in that total were 76 rigs that were not being marketed. Some of the rigs in this category might not be returned to service due to the costs that would be associated with meeting U.S. Coast Guard certification requirements and classification society standards. Since offshore drilling rigs are mobile, improved market conditions in the Gulf of Mexico could potentially attract rigs to relocate from foreign waters. Taking into account increasing drilling efficiencies as well as annual attrition rates of 5% for deepwater rigs and 7% for all others, this study projects that 72 additional rigs—either reactivated, new construction, or

Table 9

Gulf of Mexico Drilling Rig Inventory

	Total	Marketed	Contracted	Not Marketed
Jackup	*139*	*119*	*105*	*20*
Semis	*38*	*34*	*27*	*4*
Drillships	*3*	*3*	*3*	*0*
Submersibles	*7*	*1*	*1*	*6*
Total Mobile	187	157	136	30
Platform	78	57	37	21
Inland Barges	95	70	34	25
All Offshore	**360**	**284**	**207**	**76**

Source: Offshore Data Services, *Rig Locator*, September 24, 1999.

relocations—will be needed by 2015 for the increased offshore activity. This total includes 10 deepwater rigs, 32 platform rigs, and 30 jack-up rigs and barges. If all of these additions were met by new construction, capital requirements would be approximately $7 billion.

Supply Finding 4: Investment in research and development is needed to maintain the pace of advancements in technology.

As stated earlier, technology advancement has played a major role in the increase of the North American resource base by:

- Improving efficiency of drilling, equipment, operating, and other costs
- Increasing recovery factors of discovered oil and gas in place
- Improving success rates (i.e., reducing the number of dry holes)
- Revealing new areas and types of resources for exploitation through innovative geologic and engineering concepts.

The above improvements occurred mainly due to advances in 3D seismic, directional drilling, and improved completion techniques.

Information and communications technology also has had a widespread impact on all facets of the natural gas producing sector. The persistent improvement of computing power at consistently decreasing prices has placed increasingly powerful information technology tools in the hands of even the smallest producers, improving efficiency and reducing cost structures. Processing power is growing and allowing applications to be moved from mainframes to high-efficiency workstations. The advent of object-based and improved data storage technologies have allowed greater access to data with a high level of access in user friendly interfaces. Connectivity has been enhanced by the use of high-capacity networks, fiber, and satellite communication links, and the Internet (intranets, extranets, etc.). More importantly, these types of system advances support new paradigms of multi-disciplinary teaming.

One consideration in this constantly changing environment and workstyle is the manner in which people can adapt, modify work processes, and comfortably utilize these tools. These changes challenge management to ensure that training is constantly updated to match the fast pace of technology growth.

Advances in technology do not happen in a vacuum. All industry stakeholders will have to support continued investment in technology research and development—from the producer who must apply the newest tools/techniques to the next opportunity, to the investor who must at times be willing to sacrifice immediate gains for longer-term viability. Continued and increased funding of research and development is required for the North American resource base to live up to its potential. Cooperative measures by all parties will be required. With continued emphasis and investment, new technologies such as those listed below could have a significant impact on future gas production:

- **Improved Seismic Techniques.** Time-lapse seismic reservoir monitoring, commonly known as 4D seismic, is the comparison of 3D seismic surveys acquired at two or more points in time. This allows scientists to study the movement of fluids in the reservoir. Another technique, multi-component technology, provides a more detailed picture of a subsurface reservoir's internal architecture. The combination of these two technologies with visualization technology allows geoscientists to "see" reservoir events such as a gas cap enlarging as oil is produced. In the future, real-time reservoir models will use these techniques to allow quick updating as new data are available, thus enabling drilling and field development decisions to be made quickly to enhance production.
- **Deep Wireline Measurements.** Deep measurements of gravity and electromagnetic forces provide information that complements the seismic data. Wireline-based deep measurements typically have higher resolution than seismic and can provide enhanced detail about gas location and movement.

- **Integrated Well Planning.** Integrated well planning is the process of effectively and accurately planning for optimum wellbore placement in the reservoir, determining suitable equipment/systems for completion and production, and maximizing reservoir output and economics.

- **Drilling Systems.** A major focus on drilling systems will continue, because drilling time is a major component of rig cost and thus the total cost of the well. Significant strides have been made in the last several years with regard to rates of penetration, equipment dependability, downhole data gathering, and drilling dynamics. The ability to steer and extend the wellbore both vertically and horizontally to zones of interest has increased significantly with the advent of extended reach wells, horizontal drilling, and multi-laterals

- **Deepwater Technology.** As exploration and production activities move deeper into the ocean, new technology will be essential for advancing offshore production systems. Traditional platforms are being replaced with new designs and subsea completions are becoming common place. New systems such as Floating Production Systems may have the potential to significantly extend producing systems to the ultra-deepwater areas if technology and cost challenges can be met.

The current study presumes that these technology advances and many others will form the basis for new innovations that increase exploratory success and optimize well production capability. Should technology advancements materialize at a slower rate, or should these technologies prove less valuable to producers than expected, the availability of future supply and the cost at which it is delivered could be impacted.

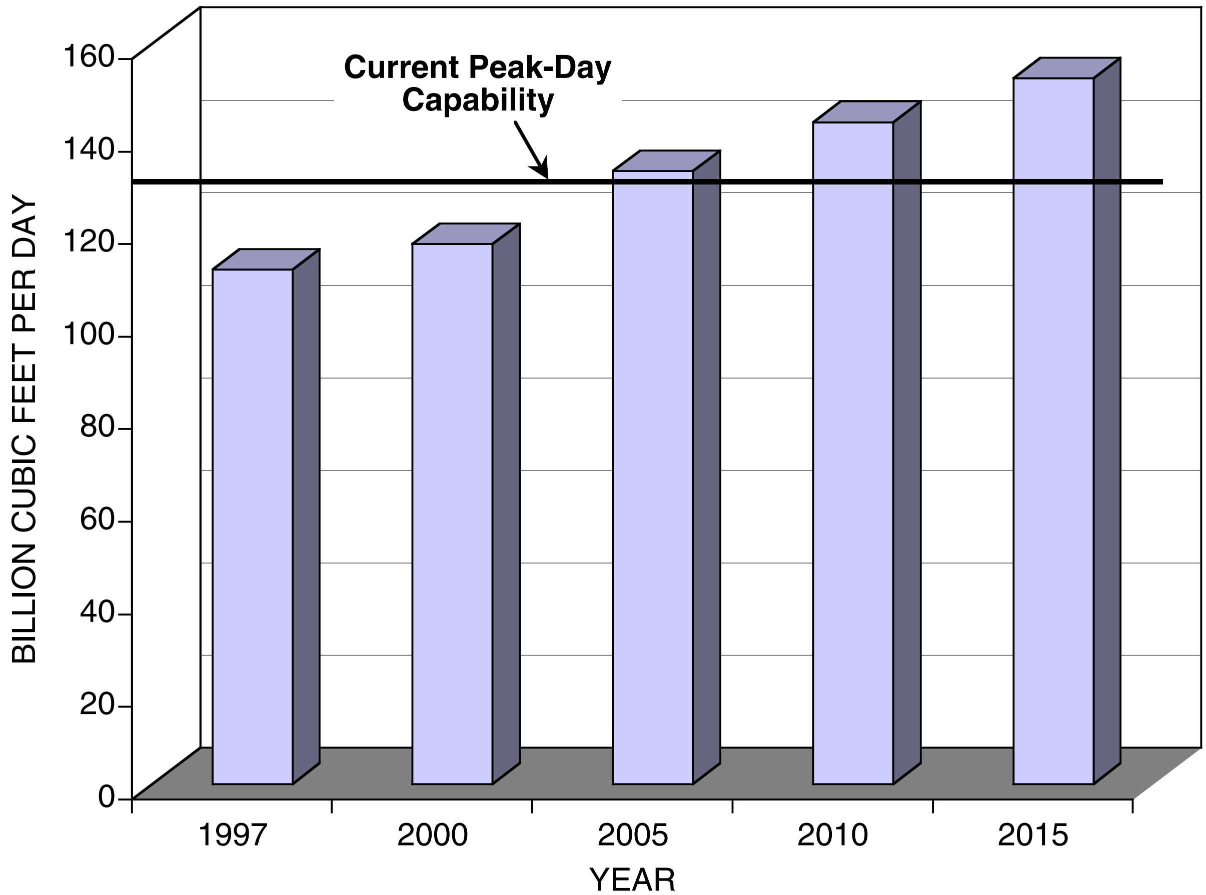
FINDINGS OF THE TRANSMISSION AND DISTRIBUTION TASK GROUP

Transmission/Distribution Finding 1: Significant expansion and enhancements to the delivery system are required to serve the growing demand.

Substantial changes are expected in natural gas supply and consumption patterns by 2015, which creates a need for enhancements to the existing delivery system and construction of new transmission and storage facilities. By 2015, annual requirements are projected to increase beyond 31 TCF, which equates to 88 BCF per day. Peak-day requirements will grow from approximately 111 BCF per day in 1997 to over 152 BCF per day in 2015, as shown in Figure 20. A significant investment in pipeline facilities will be necessary to meet the new demand requirements and shifts in supply locations to deepwater Gulf of Mexico, Rockies, western Canada, and the Canadian Atlantic. These frontier supply basins will have increased pipeline costs because of their more distant location from markets, mitigation of potential environmental impacts, and harsher environments for construction, maintenance, and operation. However, the annual average expenditures projected in this study are consistent with historical trends.

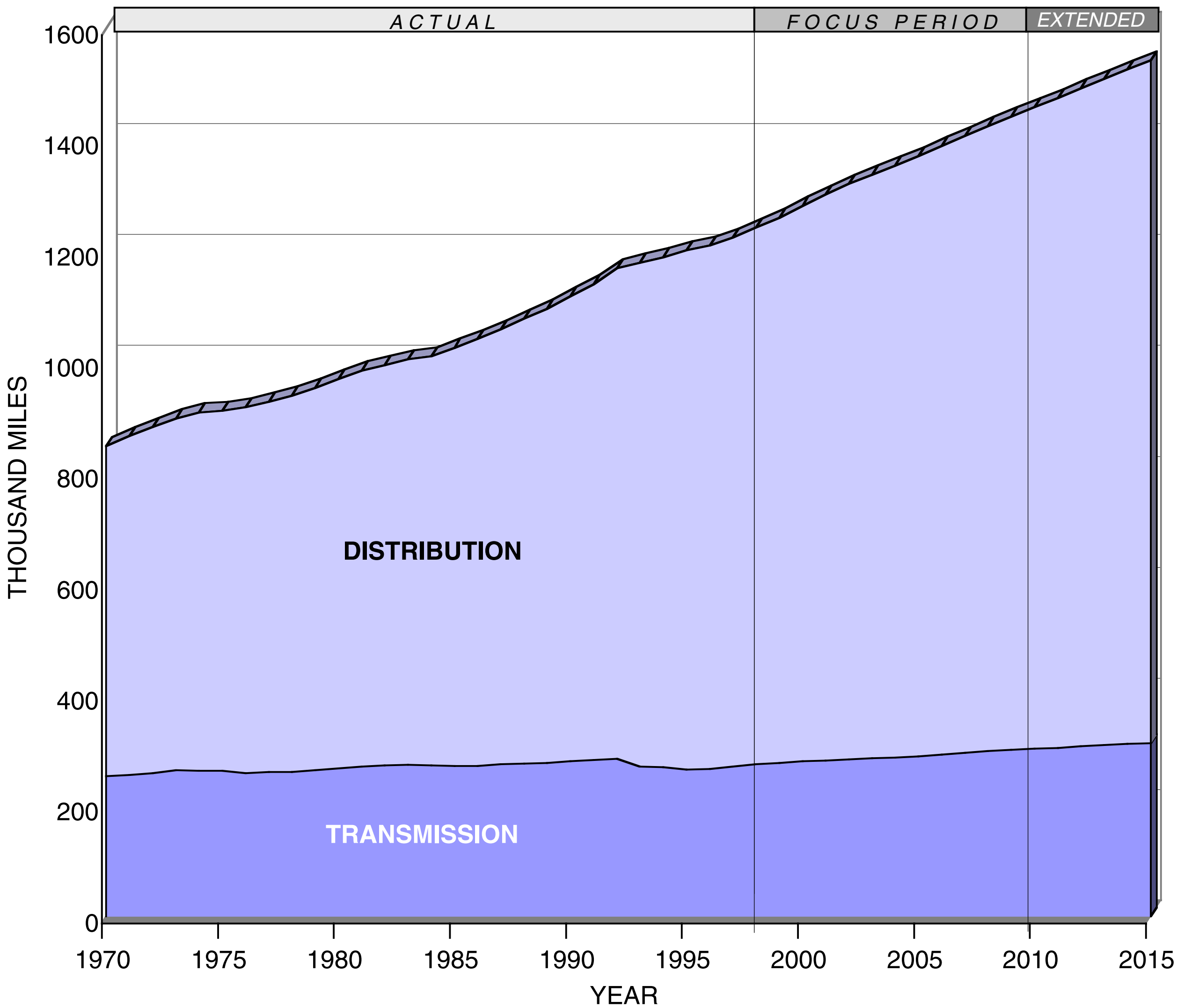
The consumption of natural gas in the United States previously peaked in 1972 at 22.1 TCF. Since then, geographic shifts in supply and demand (such as the decline of the industrial Midwest and increases in supply from the Rockies and Canadian imports) has caused the transmission and storage system to expand more slowly than otherwise expected. Today there are more than 270,000 miles of gas transmission pipelines and approximately 3.2 TCF of working gas storage capacity (Figures 21 and 22). The U.S. delivery system also includes another 952,000 miles of gas lines owned by the distribution segment of the industry. Through 2015, approximately 38,000 miles of transmission pipeline and 255,000 miles of distribution mainlines are projected to be needed to meet the requirements of the projected market. This rate of growth is comparable to the expansion experienced in the last few years. In addition, working gas storage will increase by 0.8 TCF.

Figure 20. Peak-Day Demand by Year



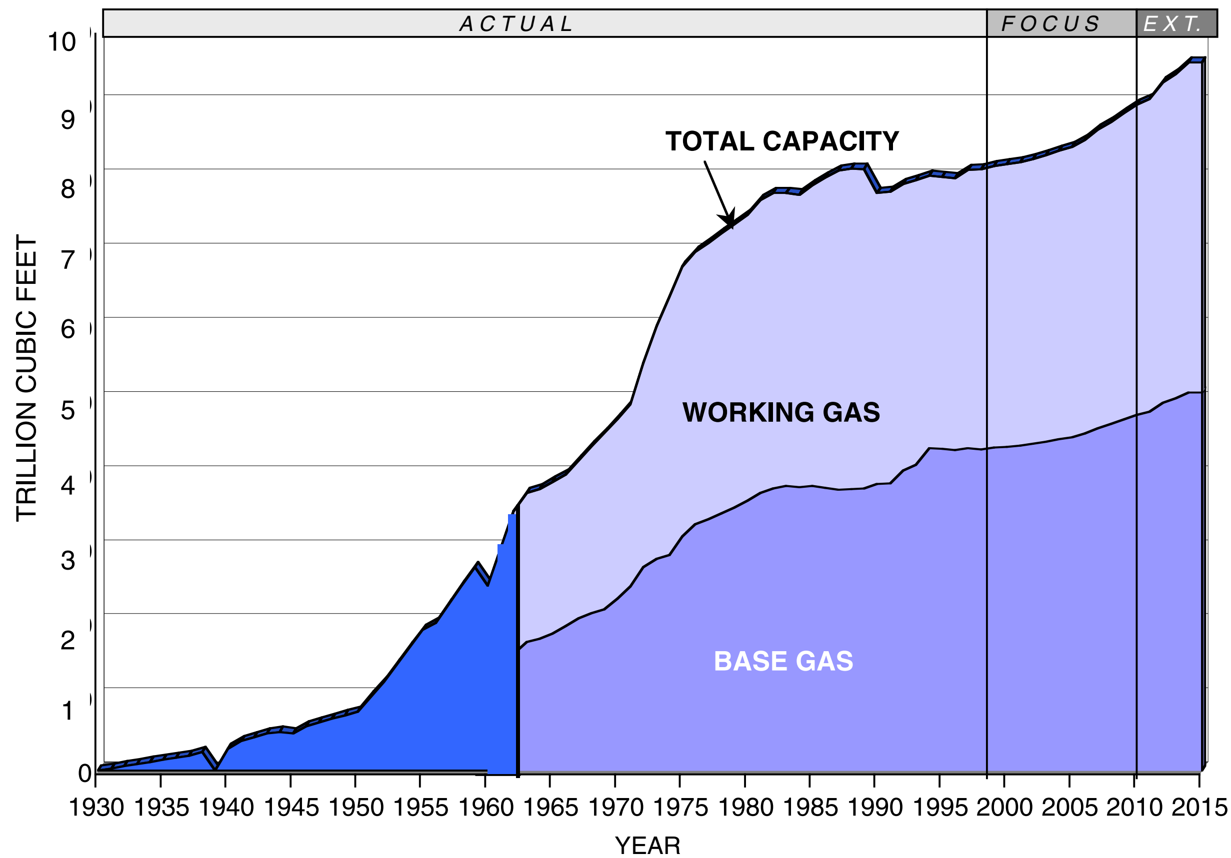
Source: EEA, Inc., Gas Market Data and Forecasting System

Figure 21. U.S. Natural Gas Pipeline
Cumulative Mileage



Source of historical data: AGA, Gas Facts1998

Figure 22. Underground Natural Gas Storage Capacity



NOTE: Prior to 1962, storage data not distinguished between Base Gas and Working Gas.

Sources: Total Capacity: AGA, Engineering Technical Note, Underground Storage in the U.S. And Canada--1990, April 1991
Base Gas: EIA, Annual Energy Review 1990, p. 175
Working Gas = Total minus Base

The existing transmission and storage system is capable of meeting its existing firm requirements on an annual and peak-day basis. Analysis indicates that the system had a 1997 annual capacity of 45 TCF and a daily capacity of 131 BCF. This additional capacity above the 1998 annual consumption of 22 TCF, and estimated firm peak-day demand of 111 BCF per day, allows non-firm customers to use this capacity on peak days, provides necessary redundancy, adds reliability, and enables the system to support a growing U.S. gas market.

Peak-day requirements represent the sum of all loads on a system on the day of highest demand (as measured by volume). Any particular system must have the ability to meet its customers' firm requirements on design peak days. Gas utility systems use a combination of flowing gas and storage gas to meet their customers' firm requirements on these days. The space-heating load is highly dependent on the impact of unpredictable winter weather. For this reason, almost all U.S. gas pipelines and distribution companies experience their peak day during the winter months. During the remaining months of the year, these utilities have unutilized capacity beyond that needed to meet market requirements and to refill storage.

In general, the increased demand projections for 2010 and 2015 in the residential, commercial, and industrial sectors will also increase peak-day requirements and thus necessitate construction of additional pipeline and storage facilities. Contracts with some customers, principally industrials and electricity generators, may limit consumption on peak days and allow (or require) them to switch to another fuel. Some customers are unable to switch fuels due to restrictions from environmental regulations. This is becoming more common, particularly for the new electricity generation facilities, as fuel-switching capabilities are becoming more difficult to permit in some areas of the United States. Thus, the new electricity generation load will likely have a higher impact on peak-day requirements than in the past. However, some level of fuel-switching capability is necessary to handle overall energy needs on peak days and to lessen pipeline and storage expansion needs.

Two shifts in the flows on the transmission system have developed recently. The first is the decrease in Gulf Coast and Midcontinent supply moving to the Midwest (i.e., Chicago area). This was caused by slow market growth in the Midwest and displacement of Gulf Coast and Midcontinent supply by Rockies and western Canadian supply as additional pipeline infrastructure has come on line. The second is the increase in Gulf Coast supply to the Southeast that was caused by the large increase in market demand. Supply increases from the Rockies and western Canada will be landing in the Midwest area, turning Chicago into a supply hub at some point in the near future. The Reference Case shows that significant new or incremental transmission capacity will be built from the Rockies to California, Canadian Atlantic to New England, Gulf of Mexico to Florida, western Canada to the Pacific Northwest, and the MacKenzie Delta to Alberta.

Transmission/Distribution Finding 2: Access issues impede installation of new infrastructure.

The anticipated shifts in supply regions and regional growth patterns will require building pipelines to tap new supply sources, expanding infrastructure along existing corridors, building laterals to attach new markets, and attaching new storage facilities to the pipeline grid. A fundamental requirement to develop this infrastructure is access to land for attaching, gathering, and processing the natural gas and then transporting the natural gas to market or to storage fields for eventual delivery to market.

Issues related to access have become more prominent for the transmission and distribution sectors of the industry. Access issues arise from urban sprawl encroaching on potential and existing rights of way, heightened public resistance to providing easements, and increasingly restrictive government policies and regulations. Some of these issues are exemplified by public protest to recently proposed pipeline projects from the Midwest to serve Northeast markets. Both industry and government have taken action to address the public's concerns. For example, FERC recently amended regulations by adding landowner notification requirements and also issued orders to help facilitate pipeline projects. However, the following examples of proposed policy/regulatory changes demonstrate the movement toward additional requirements for the building and maintenance of pipelines.

- The U.S. Fish & Wildlife Service (FWS) has developed a "Draft Compatibility Policy Pursuant to the National Wildlife Refuge System Act of 1997" that would significantly impact the ability to obtain permits from the FWS for non-wildlife-dependent activities.
- On July 21, 1999, the Corps of Engineers proposed to modify Nationwide Permits in certain areas, which if implemented could affect the ability to obtain permits in a timely and cost-effective manner.
- On September 15, 1999, the Federal Energy Regulatory Commission issued a Statement of Policy (Docket No. PL99-3-000) that it will use in deciding whether to authorize the construction of major new pipeline facilities. The change in policy now requires that an applicant demonstrate that the economic benefits to the public outweigh adverse impacts. Only when the benefits outweigh the adverse effects on economic interests will the Commission proceed to complete the environmental analysis and consider other interests. Prior to this policy change the economic test was much simpler, relying on the percentage of long-term contracts as the measure of demand for a proposed project.

Careful consideration must be given to these and similar issues in order to balance the myriad of interests that exist. The consequences of conflicting policy and regulations within and across government agencies will lead to higher costs, either directly or via delays. Natural gas has its own environmental benefits that should be taken into account when formulating policy so that an appropriate balance can be achieved.

Transmission/Distribution Finding 3: New services are needed to serve a changing market.

The evolving competitive nature of the natural gas industry requires new mechanisms for existing and new customers to gain access to transportation services at competitive prices. As the LDCs' requirements to hold interstate pipeline capacity decline, marketers, producers, and other end-users will be contracting for the capacity. Many of these customers use capacity differently than the LDCs, because their individual load requirements and physical capabilities differ from the aggregated load and system capabilities of the LDCs.

The current delivery system was built and optimized over decades to meet the design peak-day requirements of firm service customers that are primarily residential, commercial, and to a lesser extent, industrial and electricity generation customers. To date, the "seasonal slack or off-peak slack" in the delivery system has been adequate to meet the levels of demand placed on this system by electricity generators. Looking ahead, the anticipated tremendous growth in electricity generation demand for natural gas will require the delivery system to be re-optimized to meet larger off-peak swing loads as well as growing peak-day requirements. For example, electricity generators (using high-efficiency combustion turbines) require significantly higher inlet pressures and higher hourly flow rates than other end-use customers (and previous generation turbines). In addition, the loads for peaking generators are volatile and of relatively short duration, thereby requiring greater flexibility and quicker responses by the natural gas delivery system. Meeting these requirements, as well as the increasing peak-day requirements of the other sectors, on a significantly larger scale will entail changes in physical capabilities, operational procedures, communications, contracting (supply and transportation), and tariffs.

Transmission/Distribution Finding 4: The restructured market changes the risks associated with investments for new infrastructure.

While the capital required for transmission and distribution infrastructure expansions is not of the same magnitude as for the upstream sectors, investment issues are just as critical. The Reference Case shows that transmission and distribution companies will need to make capital investments of approximately $123 billion through 2015. This total includes $34 billion for transmission pipelines, $84 billion for distribution facilities, and $5 billion for storage. Clearly, companies will need to make considerable investments in infrastructure to serve new customers, manage seasonal and peak-day demand swings, and replace aging facilities. The magnitude of the expenditures is in line with historical averages, but restructuring has introduced new risks associated with investments.

The primary question that looms in this segment of the industry is about who will accept the risk of financing and constructing major new facilities. In the past, downstream investments in gas pipelines and storage fields were heavily regulated. LDCs, as franchise holders, had principal access to the end-use market and thus had a level of certainty that supported the investment in new facilities. The industry restructuring over the last two decades has led to changing roles and obligations—as well as new risks and different risk profiles—for all the industry participants. Many pipeline shippers now attach little value to holding contracts for firm service of more than three years. The shippers' need to limit their long-term exposure does not align with the pipelines' need for long-term contract commitments to justify investment risk. In addition, industry restructuring can impose a myriad of challenges/risks to gas utilities that should be considered in the regulatory process. Faced with these changing conditions, it is not clear who will be willing to accept the risks for building the infrastructure needed to support the growth in natural gas demand.

The Secretary of Energy
Washington, DC 20585
May 6, 1998

Mr. Joe B. Foster
Chair
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Foster:

In 1992, the National Petroleum Council released a study entitled, "Potential of Natural Gas in the United States." That study was critical in identifying natural gas as an abundant domestic resource that can make a significantly larger contribution to both this Nation's energy supply and its environmental goals.

Since the release of the study, the Nation has experienced five years of sustained growth in the use of natural gas. In addition, the study did not anticipate at least two major forces that are beginning to take shape, which will profoundly affect energy choices in the future -- the restructuring of electricity markets and growing concerns about the potentially adverse consequences that using higher carbon-content fuels may have on global climate change and regional air quality. These issues offer opportunities and challenges for our Nation's natural gas supply and delivery system. For a secure energy future, Government and private sector decision makers need to be confident that industry has the capability to meet potentially significant increases in future natural gas demand.

Accordingly, I am requesting that the Council reassess its 1992 study taking into account the past five years' experience and evolving market conditions that will affect the potential for natural gas in the United States to 2020 and beyond. Of particular interest is the Council's advice on areas of Government policy and action that would enable natural gas to realize its potential contribution toward our shared economic, energy, and environmental goals.

Given the significance of this request, Deputy Secretary Elizabeth Moler will co-chair the study committee. I offer my gratitude to the Council for its efforts since our meeting in December 1997, to assist the Department in defining a more concise study scope. The breadth of issues related to natural gas supply and demand is vast and I recognize that further refinements in scope may be necessary once the study is underway to address the most significant concerns about future natural gas availability.

Sincerely,

Federico Peña

The Secretary of Energy
Washington, DC 20585

November 18, 1998

Mr. Joe B. Foster
Chair
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Foster:

This is to convey my approval to establish a Committee on Natural Gas and to appoint industry members as proposed in your letter of October 6, 1998. I also approve the establishment of a coordinating subcommittee and the appointment of subcommittee members identified in your letter.

The Deputy Secretary will serve as the Government co-chair of the committee; the Assistant Secretary for Fossil Energy will co-chair the coordinating subcommittee. Staff involved in this study will be from the Office of Fossil Energy and the Office of Policy and International Affairs. In addition, the Energy Information Administration has expressed an interest in providing technical and analytic support. The Deputy Assistant Secretary for Natural Gas and Petroleum Technology will serve as the alternate for the Government co-chair of the subcommittee.

I agree that it would be appropriate for a representative of the Department of the Interior to be a member of the coordinating subcommittee, and we are pursuing this issue.

For a secure energy future, Government and private sector decision-makers need to be confident that industry has the capability to meet the significant increases in natural gas demand forecasted for the twenty-first century. I am pleased that the National Petroleum Council recognizes the challenge facing the domestic natural gas industry and has agreed to conduct a study of natural gas supply availability. I look forward to the study's results.

Yours sincerely,

Bill Richardson

Bill Richardson

BACKGROUND INFORMATION ON THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council (NPC) on June 18, 1946. In October 1977, the Department of Energy was established and the Council was transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary, relating to oil and natural gas or the oil and gas industries. Matters that the Secretary would like to have considered by the Council are submitted in the form of a letter outlining the nature and scope of the study. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of recent studies undertaken by the NPC at the request of the Secretary include:

- *Emergency Preparedness for Interruption of Petroleum Imports into the United States* (198l)
- *U.S. Arctic Oil & Gas* (198l)
- *Environmental Conservation – The Oil & Gas Industries* (1982)
- *Third World Petroleum Development: A Statement of Principles* (1982)
- *Petroleum Inventories and Storage Capacity* (1983, 1984)
- *Enhanced Oil Recovery* (1984)
- *The Strategic Petroleum Reserve* (1984)
- *U.S. Petroleum Refining* (1986)
- *Factors Affecting U.S. Oil & Gas Outlook* (1987)
- *Integrating R&D Efforts* (1988)
- *Petroleum Storage & Transportation* (1989)
- *Industry Assistance to Government – Methods for Providing Petroleum Industry Expertise During Emergencies* (1991)
- *Short-Term Petroleum Outlook – An Examination of Issues and Projections* (1991)
- *Petroleum Refining in the 1990s – Meeting the Challenges of the Clean Air Act* (1991)
- *The Potential for Natural Gas in the United States* (1992)
- *U.S. Petroleum Refining – Meeting Requirements for Cleaner Fuels and Refineries* (1993)
- *The Oil Pollution Act of 1990: Issues and Solutions* (1994)
- *Marginal Wells* (1994)
- *Research, Development, and Demonstration Needs of the Oil and Gas Industry* (1995)
- *Future Issues – A View of U.S. Oil & Natural Gas to 2020* (1995)
- *Issues for Interagency Consideration – A Supplement to the NPC's Report: Future Issues – A View of U.S. Oil & Natural Gas to 2020* (1996)
- *U.S. Petroleum Product Supply—Inventory Dynamics* (1998).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of the oil and gas industries and related interests. The NPC is headed by a Chair and a Vice Chair, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

NATIONAL PETROLEUM COUNCIL

MEMBERSHIP
(158)

December 15, 1999

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NATIONAL PETROLEUM COUNCIL

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LeTourneau, Inc.

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Holiday Companies

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James A. Gibbs
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Frederic C. Hamilton
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Appendix C

Historical Overview of Natural Gas Industry

Natural gas has been consumed as a fuel in this country since 1816, when gas manufactured from coal was used to illuminate the streets of Baltimore, Maryland. Consumers of gas in the 1800s burned gas produced or manufactured locally, as the technology to transport gas long distances did not yet exist. A national market, supplied by interstate pipeline transmissions systems, began to evolve in the 1920s with the development of seamless welded pipe. This technology allowed the long distance transportation of remote supplies of "natural" gas for which no market existed to markets previously served by more expensive manufactured gas or less desirable fuels, primarily coal. The gas market continued to evolve and grow over the next 50 years in spite of major wars, economic recessions, and regulatory enactments. Annual gas consumption grew from 2 trillion cubic feet (TCF) in 1930 to a level of 22 TCF in 1972.

Much of the growth in demand in the 1960s and early 1970s was driven by below-market prices attributable primarily to the artificially low field prices produced by federal regulation. Low field prices produced inadequate returns for producers, with the result that exploration and development fell off and supply declined. The resulting imbalance between supply and demand resulted in curtailment proceedings at the federal and state levels in which available supply was allocated among end-users. As a result of these proceeedings, natural gas gained a reputation as an unreliable fuel. Subsequent deregulation of field prices produced a temporary price spike, which further dampened demand and produced the impression that gas was only available at a premium to market clearing prices. The passage of the Natural Gas Policy Act of 1978 (NGPA) and the opening of the nation's gas transmission systems eventually produced a balance between supply and demand at market clearing prices.

Natural Gas Act of 1938

As already noted, the development of seamless welded pipe made the long-distance transmission of natural gas possible and allowed the large gas discoveries of the 1920s and 1930s to reach previously unserved interstate markets. The courts held that state regulatory agencies lacked power to regulate the rates and services of interstate pipelines. This upstream "regulatory gap" led to the passage of the Natural Gas Act in 1938. The Federal Power Commission (FPC, forerunner of the Federal Energy Regulatory Commission) quickly assumed jurisdiction over the rates and services of interstate pipelines and the issuance of certificates of public convenience and necessity to construct pipeline facilities.

The Phillips Decision

Because the FPC believed it lacked jurisdiction, it did not regulate the price of gas at the wellhead (field prices) in the years immediately following the passage of the Natural Gas Act. However, in *Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672 (1954), the Supreme Court ruled that the Natural Gas Act required regulation of the price of natural gas at the wellhead.

Since traditional cost-of-service regulation would have been administratively impossible for individual gas contracts, the FPC developed various schemes to establish field prices on a broader basis, including "in-line pricing," "area prices," and "vintaging." The Commission unfortunately erred on the side of low prices. Field prices of gas sold into the unregulated intrastate market gradually rose above the price of newly contracted interstate gas and diverted supplies away from the interstate market. The effect of artificially low interstate gas prices stimulated demand, yet discouraged natural gas exploration activities. By the early 1970s, spot shortages of gas began to appear and industrial users became subject to frequent interruption. Gas was allocated to end-users in curtailment proceedings instead of by market forces. During the harsh winter of 1976–77, the artificially induced shortage became severe and gas deliveries throughout the Northeast, Midwest, and Mid-Atlantic states were curtailed to varying degrees.

Natural Gas Policy Act of 1978

The emergency of the winter of 1976–77 produced a general consensus that legislative action was necessary to remedy natural gas shortages. With that consensus and against a backdrop of competing interests Congress produced a complex series of compromises that became the Natural Gas Policy Act of 1978.

The objective of the NGPA and its companion legislation, the Power Plant and Industrial Fuel Use Act, was to raise gas prices in order to encourage gas production while restricting its consumption by non-core market segments. Complete and immediate decontrol of wellhead prices was not achievable due to consuming states' concerns about the impact of a rapid price rise on their citizens. What passed was a "phased decontrol" of a complete array of different categories of gas. That decontrol is now complete, and restrictions on the use of gas for various purposes have been eliminated.

The higher prices for new gas that resulted from the passage of the NGPA were effective in increasing the exploration and production of natural gas. Interstate pipelines and local distribution companies (LDCs), inspired by memories of past shortages, quickly contracted for new supplies under pricing provisions that produced premium prices. The higher gas prices, however, discouraged demand. By the early 1980s, the cumulative effect of increased supply, demand erosion, end-use restrictions, and recession had turned a gas supply shortage into a gas supply surplus. A spot market consisting of new supplies developed and the spot price quickly fell below the weighted average cost of the mix of pipeline supplies. Industrial customers who could switch to alternative fuels did so, thus further depressing gas demand. Proposals to allow access to spot market gas to service industrial users who would otherwise switch to alternative fuels were proposed by the pipelines and approved by the Federal Energy Regulatory Commission (FERC) as "special marketing programs."

In the 1985 case of *Maryland People's Counsel v. FERC,* the D.C. Court of Appeals held that such preferential access to spot market gas was discriminatory and FERC was directed to respond by providing non-discriminatory access. Order 436, issued in October of 1985, required that pipelines provide non-discriminatory access to transportation systems and services. As pipelines began to transport spot gas for resale customers under this order, they displaced their own sales gas and their "take-or-pay" liabilities under existing contracts, already large, mushroomed.

FERC Orders 500 and 528

FERC Order 500 allowed pipelines to "direct bill" a portion (generally, 50%) of their take-or-pay costs to LDC customers on the basis of past purchase levels from the affected pipelines. With the possibility of at least partial recovery of "take-or-pay" costs, pipelines quickly entered into negotiations with producers to quantify those costs. As a result of these negotiations, above-market contracts were restructured or eliminated altogether in return (generally) for large, up-front cash payments. The D.C. Court of Appeals, after having first invalidated the "direct bill" provisions of Order 500 due to its retroactive nature, ultimately agreed to the substitute allocation method promulgated by FERC in Order 528.

FERC Orders 636, 636A, and 636B

FERC Orders 636, 636A, and 636B virtually eliminated the pipeline merchant functions and converted interstate pipelines into common carriers. Gas purchasing responsibilities were transferred to LDCs and direct purchasers. State regulators inherited the responsibility for regulatory oversight of gas purchasing practices. In turn, many state commissions have mandated transportation of gas by LDCs with the result that end-users can purchase gas directly from producers and arrange transportation through both pipelines and LDCs.

Natural gas is now sold to LDCs, various intermediaries, and a range of gas users by a large number of gas producers, independent marketers, marketing associations, storage companies, and the like. Pipelines and LDCs transport this gas between buyer and seller. In addition to cash markets, there is an active futures market on the New York Mercantile Exchange (NYMEX), and even longer term arrangements to buy or sell gas can be arranged privately through derivative instruments. In contrast with the distortions produced by the heavy regulatory hand of the past, it is generally recognized that the markets for gas—though volatile because of changing perceptions concerning weather, inventories, and other supply/demand factors—are both competitive and orderly.

Acronyms and Abbreviations

BCF	billion cubic feet
Btu	British thermal unit
CDD	cooling degree days
EEA	Energy and Environmental Analysis, Inc.
EEI	Edison Electric Institute
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GDP	gross domestic product
HDD	heating degree days
KWH	kilowatt hours
LDC	local distribution company
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MCF	thousand cubic feet
MMBtu	millions of British thermal unit
NERC	North American Electric Reliability Council
NYMEX	New York Mercantile Exchange
OCS	Outer Continental Shelf
RACC	refiners average cost of crude
SNG	synthetic natural gas
TCF	trillion cubic feet
WTI	West Texas Intermediate

Glossary

Assessed Additional Resources: The sum of natural gas deposits estimated to be in-place (using accepted engineering models and analytical tools) that will become recoverable in the future at various assumed technology and price levels; current economic and operating conditions are insufficient to justify Proved Reserves status for this category.

Cumulative Production: The total volume of natural gas that has been withdrawn from producing reservoirs.

New Fields: A quantification of resources estimated to exist outside of known fields on the basis of broad geologic knowledge and theory; in practical terms, these are statistically determined resources likely to be discovered in additional geographic areas with geologic characteristics similar to known producing regions, but which are as yet untested with the drillbit.

Nonconventional Gas: Resources that are estimated to be contained in known strata of deposits requiring application of technologies different from those required to extract conventional high permeability gas reserves (i.e., shale gas, coal bed methane, tight gas, etc.).

Old Field Reserve Appreciation: Additional estimated conventional resources resulting from the recognition that currently booked Proved Reserves are conservative by definition and will continue to grow over time; based on historical experience, existing fields have been shown regularly to contain, and ultimately produce, significant additional quantities of natural gas in excess of initial proved reserve estimates.

Proved Reserves: The most certain of the resource base categories representing estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions; generally, these gas deposits have been "booked," or accounted for as assets on the SEC financial statements of their respective companies.

Synthetic Natural Gas: A manufactured product chemically similar in most respects to natural gas, resulting from the conversion or reforming of petroleum hydrocarbons or from coal gasification. It may easily be substituted for or interchanged with pipeline quality natural gas.

Total All-Time Recovery: The sum of Total Remaining Resources plus Cumulative Production; the estimate of total natural gas that will ultimately be produced after all wells cease economic production.

Total Remaining Resources: The sum of Proved Reserves and Assessed Additional Resources; this term is often used interchangeably with "Total Resources" and refers to the total quantity of natural gas estimated to remain available for production.